APF ENERGY TRUST

2004
ANNUAL REPORT

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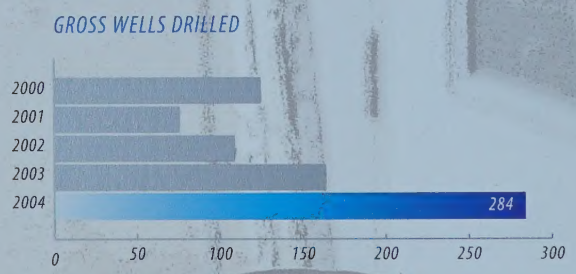
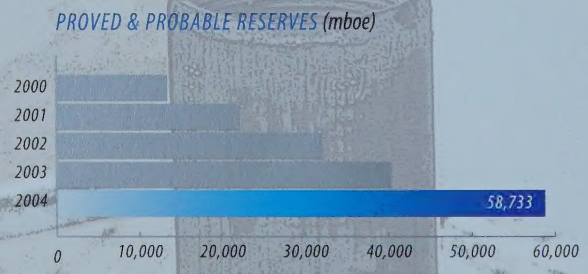
ENERGY...





APF Energy Trust is a dynamic, growth-oriented royalty trust created in December, 1996, to provide unitholders with high distributions based on cash flow generated from high quality oil and gas properties. Through strong acquisitions and effective optimization initiatives, APF has significatly increased production from 1,700 boe/d in the fourth quarter of 1996 to an average of 18,450 boe/d during the fourth quarter of 2004. Since completing its initial public offering at $10 per unit, the Trust has declared cumulative distributions of $16.00 per unit to December, 2004, rewarding unitholders with an average annual return of 22%.

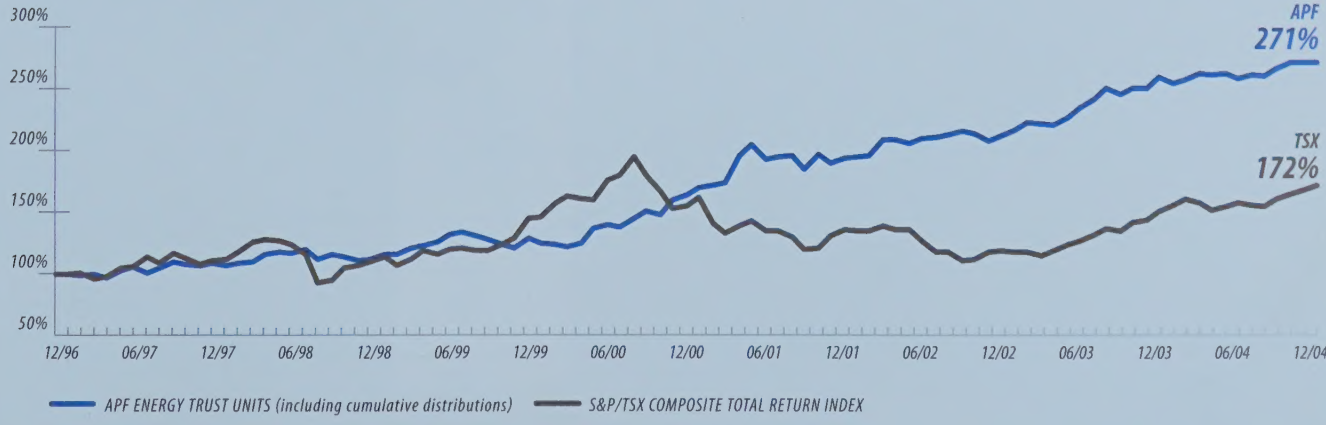
ANNUAL MEETING

The Annual Meeting of the Unitholders of APF Energy Trust will be held on May 4, 2005 at 3:00 pm in the Roxy Theatre at the Sun Life Conference Centre (mezzanine level), 140 - 4th Avenue S.W., Calgary, Alberta.

WE'VE GOT LOTS OF IT.

APF RELATIVE PERFORMANCE

APF Energy Trust units ("AY.UN") are traded on the Toronto Stock Exchange. The following graph illustrates APF's strong and consistent performance relative to the S&P/TSX Composite Total Return Index.



SUMMARY of OPERATING and FINANCIAL RESULTS

Twelve Months Ended December 31	2004	2003 Restated[3]	% Change
FINANCIAL			
($000, except per unit/boe amounts)			
Cash flow from operations[1]	107,126	81,019	32%
Per unit - basic	$2.21	$2.62	(16%)
Per unit - diluted	$2.03	$2.42	(16%)
Distributions declared	96,930	68,713	41%
Per unit	$2.00	$2.20	(9%)
Payout ratio	90%	85%	6%
Bank debt	169,000	98,000	72%
Operating expenses per boe	$8.84	$7.12	24%
Operating netbacks per boe (before derivatives)	$25.42	$23.40	9%
Market			
Units outstanding (000s)			
End of period	58,845	34,074	73%
Weighted average - basic	48,486	30,970	57%
Weighted average - diluted	52,869	33,489	58%
Trust unit trading			
High	$12.63	$12.67	–
Low	$10.32	$9.30	11%
Close	$11.72	$12.54	(7%)
Average daily volume	305,706	163,000	88%
OPERATIONS			
Daily production (average)			
Crude oil (bbl)	6,969	6,472	8%
NGLs (bbl)	758	358	112%
Natural gas (mcf)	49,712	33,799	47%
Total (boe)[2]	16,012	12,463	28%
Average commodity prices ($Cdn.)			
Total crude oil (bbl)	$44.63	$36.07	24%
NGLs (bbl)	$40.09	$31.83	26%
Natural gas (mcf)	$6.79	$6.64	2%
Average (boe)[2]	$42.40	$37.66	13%
Proved plus probable reserves			
Oil & NGLs (mbbl)	30,498	23,789	28%
Gas (mmcf)	169,412	99,197	71%
Total (mboe)	58,733	40,322	46%
Drilling (gross wells)			
Oil	37	60	(38%)
Gas	135	80	69%
Coalbed methane	104	19	447%
Other	8	5	60%
Total	284	164	73%

(1) Management uses cash flow (before changes in non-cash working capital) to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital.

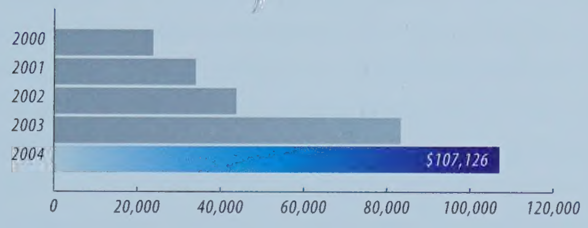
(2) BOE's may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio for natural gas of 6 Mcf: 1 bbl has been used which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(3) 2003 comparative results have been restated for the twelve month period ended December 31 to reflect changes in accounting policies.

KEY PERFORMANCE HIGHLIGHTS

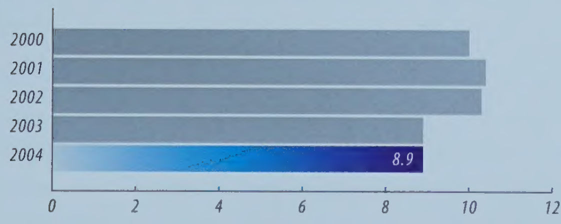
- Completed the $291.1 million acquisition of Great Northern Exploration Ltd., adding 5,600 boe/d and growing the Trust by approximately 45%.
- Recorded cash flow of $107.13 million in 2004 and declared distributions of $96.93 million, resulting in a 2004 payout ratio of 90%. APF realized cash flow of $31.1 million for the three months ended December 31, 2004, an increase of 109% over the fourth quarter of 2003. The Trust declared distributions of $28.1 million ($0.48 per unit) for the three months ended December 31, 2004.
- Drilled 284 (131.0 net) wells with a 98% success rate, a 73% increase over 2003 activity levels.
- Provided investors with a 16% cash yield throughout the year.
- Spent $67.6 million on the 2004 development program resulting in incremental production offsetting natural production declines on existing properties. Production averaged 16,012 boe/d in 2004, compared to 12,463 boe/d in 2003. Production for the three months ended December 31, 2004 averaged 18,450 boe/d.
- Strong participation levels in the Distribution Reinvestment Plan ("DRIP") provided $39.7 million of funding, which was used to partially fund the capital development program.

CASH FLOW ($000)

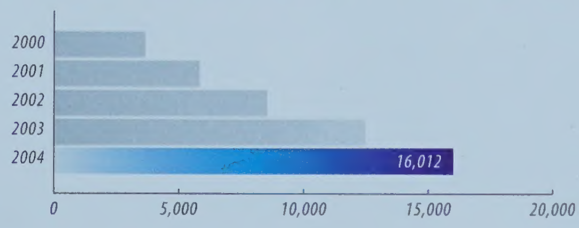


DISTRIBUTIONS PER UNIT

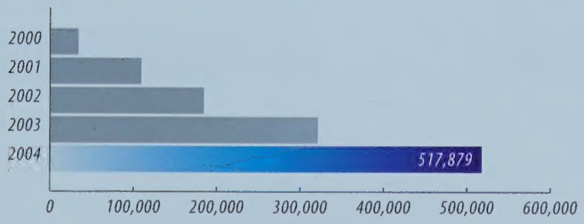
PROVED PLUS PROBABLE RESERVE LIFE INDEX (years)



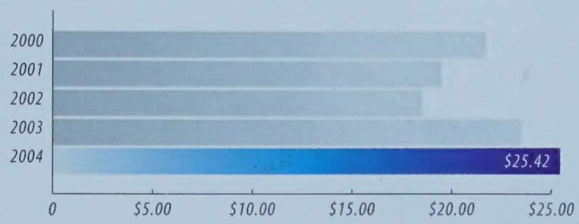
AVERAGE DAILY PRODUCTION (boe/d)



NET UNDEVELOPED LAND (acres)



OPERATING NETBACK ($/boe)



MESSAGE to UNITHOLDERS

We are pleased to present APF Energy Trust's 2004 annual report.

In our message to unitholders, we would like to discuss the importance of building a sustainable royalty trust model and our view as to the current valuation of the sector.

Building a Sustainable Model

2004 was a pivotal year for APF Energy Trust. Having completed over $570 million in corporate, asset and land acquisitions since 2001, we achieved a critical mass that allows APF to move forward with an increased focus on a full cycle business model. With 517,879 net acres, the Trust has one of the highest ratios of undeveloped land to daily oil equivalent ratios of production, confirming that unitholders are not only receiving the benefit of cash flow today, but are well positioned to take advantage of future upside. By not being reliant solely on mergers and acquisitions, APF is creating a more sustainable model.

APF successfully completed its largest corporate acquisition during 2004, with the $291 million mid-year purchase of Great Northern Exploration Ltd. ("Great Northern"). Great Northern was an example of executing the plan the Trust established several years ago: only to buy assets that have growth potential. The transaction resulted in a significant increase in production, reserves and undeveloped acreage, including a large land position in the Horseshoe Canyon coal-bed methane fairway. Development activity on the Great Northern properties was immediate and resulted in the drilling of 18 (12.3 net) wells and almost 930 mboe of incremental reserves.

During the year, the Trust's drilling activity reached an all time high, totaling 284 (131.0 net) wells with a 98% success rate. Capital expenditures of $67.6 million resulted in incremental reserves largely offsetting natural production declines on existing properties. APF added 5.4 million boe through exploration, development and other production enhancement techniques replacing 93% of annual production. On average, without accounting for acquisitions, APF has replaced 106% of annual production since 2000, one of the strongest reserve replacement track records among all royalty trusts.

Our 2005 budget contemplates spending $61.5 million and generating new production at a rate of approximately $17,000 per flowing barrel. In addition to drilling and completions, expenditures on land and seismic – although not necessarily contributing to production additions in 2005 – will help set the table for 2006 and beyond. APF has the ability to expand this budget, should we achieve certain results or if rig availability allows us to accelerate a number of operations.

The message for our unitholders and others interested in investing in APF is that we are an actively managed energy company with the expertise to extract value from our assets.

left to right:
Steven Cloutier, President and Chief Operating Officer,
Martin Hislop, Chief Executive Officer

Investing for Income: The Valuation of Trusts

The dramatic increase in oil prices during 2004 resulted in strong cash flow for the sector and even stronger valuations for most trusts. Unfortunately, APF's unit price remained flat while its peer group mostly increased in value.

We believe there are two main reasons for the lower valuation: APF's higher payout ratio; and its leverage.

With a payout ratio during 2004 of 90%, clearly there was a sentiment that APF's distribution stability was less secure than other trusts with a lower payout. Consequently, the market appeared to discount APF's price on the possibility that a distribution cut may occur.

As one of the first trusts to pioneer the concept with our very first distribution in January, 1997, APF is keenly aware of the need to retain a portion of cash flow to fund future growth. Since inception, APF's aggregate payout ratio has been approximately 87%, including several years when commodity prices were not as robust. APF managed its business effectively during a period when oil was at U.S.$11.00 per barrel and gas was at Cdn.$2.00 per mcf, pricing that most of today's trusts have not experienced.

We have always viewed APF as a vehicle for investors who want to participate in high cash flows and we have managed the business to deliver strong distributions. While the Trust has identified a target payout ratio of 80%, we believe that we can operate effectively at a higher payout while continuing to improve cash flow per unit and ultimately reach this goal.

With respect to debt, we believe that APF has been one of the most effective users of leverage in the sector. Since inception, the Trust's debt-to-enterprise value has fluctuated between 20% and 30%. In buying assets that would generate rates of return of 10% to15%, it made sense for APF to borrow funds at 5% and take advantage of the positive leverage. The very fact that yields on royalty trusts have been driven down is a testament to the prevailing view that we are structurally in a lower interest rate environment.

Investors have determined that the appropriate yield today for the royalty trust sector is, on average, approximately 12%. Many trusts traded below that during 2004, only a few basis points above bonds and debentures whose principal is protected! With a monthly distribution of $0.16 per unit, APF's yield at December 31 was approximately 16%.

As noted above, we believe that we can operate effectively at a higher payout ratio while working towards our ultimate objective. We can also continue to use leverage to our unitholders' advantage as interest rates remain low.

With the sector becoming a dual growth and yield play, those who bought early have been fortunate and have seen their capital appreciate. But that is not why royalty trusts are in business. If growth is the objective, then there is a wide array of exploration and production companies which offer that potential. However, for investors to crystallize their returns in lower yielding trusts, those securities must be sold, limiting further upside participation.

People should be investing in royalty trusts for the income. Plain and simple.

Acknowledgments

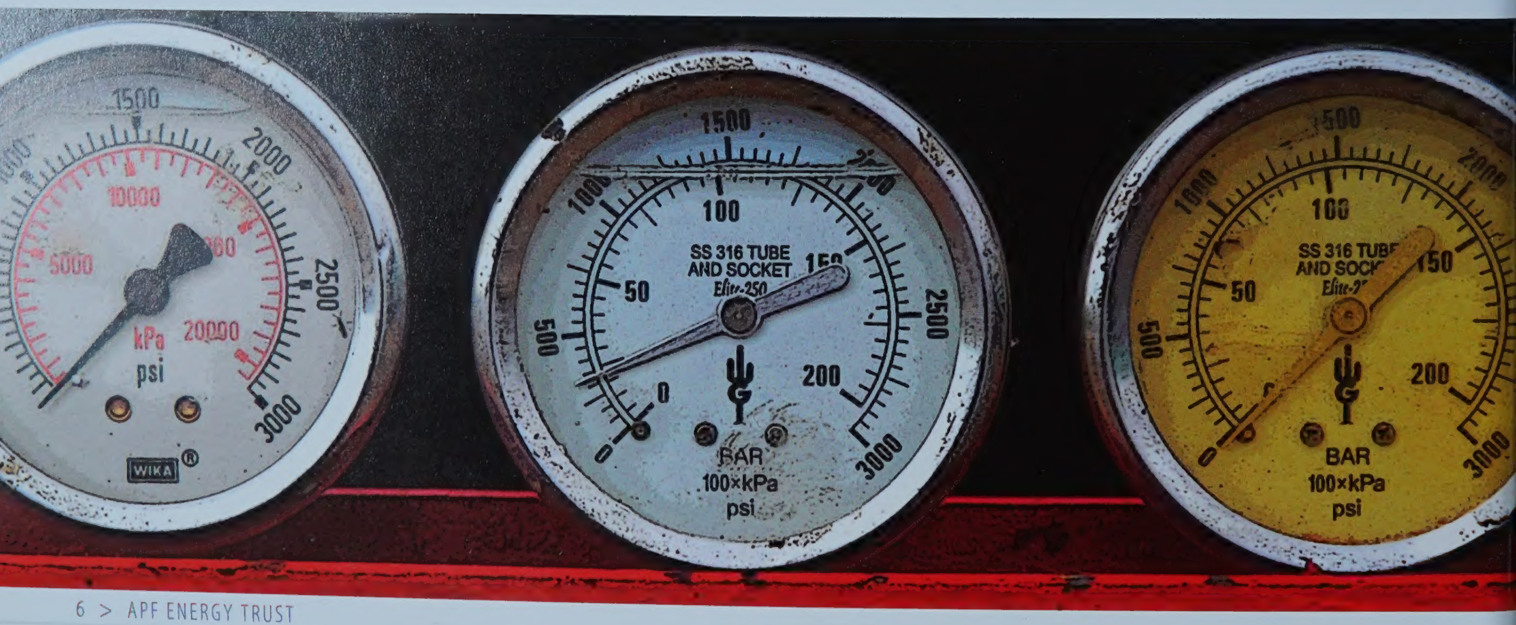
We would like to thank our staff for their tremendous efforts during 2004. Making the transition to a more sustainable model through increased drilling presented several challenges but our colleagues continue to show a determination to achieve our objectives.

We would also like to thank our Board of Directors for their guidance during the year. In particular, we want to express our appreciation to William Dickson and Daniel Mercier, who will be retiring from the APF Board at the Trust's Annual Meeting on May 4, 2005. Bill and Dan have been with APF since inception in 1996 and we are fortunate to have benefited from their experience as we grew.

Martin Hisop, Chief Executive Officer

Steven Cloutier, President and Chief Operating Officer

March 1, 2005



OPERATIONS REVIEW

APF participatio
drilling of 284 (13
wells with a 98
rate in 2004. Capital
ditures of $67
or 64% of cash flo
directed to develo
and optimization
with results
of annual productio
duction volumes
by 28% to 16,012 boe/d
during 2004.

DEVELOPMENT and OPTIMIZATION

With the acquisition of Great Northern completed during the second quarter of 2004 and the purchase of additional acreage at crown sales throughout the year, APF increased its undeveloped land base by over 60%. With 517,879 net undeveloped acres and an extensive seismic database, the Trust continued to build on 2003 momentum by drilling 284 (131.0 net) wells, representing a 73% increase over 2003 activity levels.

Drilling efforts, guided by the technical expertise in each of APF's Business Units, resulted in the Trust replacing 93% of its production on a proved plus probable basis. Proved plus probable reserve volumes grew by 46% with the inclusion of the Great Northern assets, providing a large platform for APF on which to build its future development plans.

With a $61.5 million capital budget outlined for 2005, the Trust will look to take advantage of internal opportunities and plans to drill approximately 221 (138.9 net) wells during the year. Based on this activity level, APF anticipates average daily production rates between 18,000 to 18,500 boe, with the potential to increase should the capital budget be expanded.

SOUTHEAST SASKATCHEWAN BUSINESS UNIT

KEY PROPERTIES: **Queensdale, Tatagwa, Macoun, Handsworth, Carlyle, Star Valley**

TARGET FORMATIONS: **Alida, Bakken, Frobisher, Midale**

UNDEVELOPED ACREAGE: **234,400 (63,040 net)**

2005 CAPITAL BUDGET

DRILLING & DEVELOPMENT:	**$8.6 million**
LAND & SEISMIC:	**$1.3 million**
TOTAL:	**$9.9 million**

2004 DRILLING RESULTS	Oil	Gas	Other	Dry	Total
Gross	19	0	0	1	20
Net	10.0	0.0	0.0	1.0	11.0

APF's Southeast Saskatchewan properties produce light and medium oil from Mississippian Age reservoirs. Fourth quarter 2004 production averaged 3,600 boe/d, of which 97% was oil, with an average gravity of 32° API. APF operates the majority of its Southeast Saskatchewan assets with an average working interest of 80%.

During 2004, APF invested $12.0 million of capital in Southeast Saskatchewan, of which $10.5 million was allocated to drilling, completions and tie-ins, resulting in 19 (10.0 net) oil wells and 1 (1.0 net) dry hole. The remaining $1.5 million was invested in property acquisitions, land and seismic.

In the fourth quarter of 2004, APF successfully drilled a discovery oil well at Tableland, a new exploratory property for the Trust. The Trust has established a significant land position, with a 100% working interest in 8,884 net undeveloped acres, prospective in the Bakken, Midale and Frobisher formations. Tableland is northeast of activity on the U.S. side of the border where the industry is pursuing a significant Bakken trend. APF plans to conduct a 3D seismic program at Tableland during the first quarter of 2005 as it continues to evaluate the potential for this area.

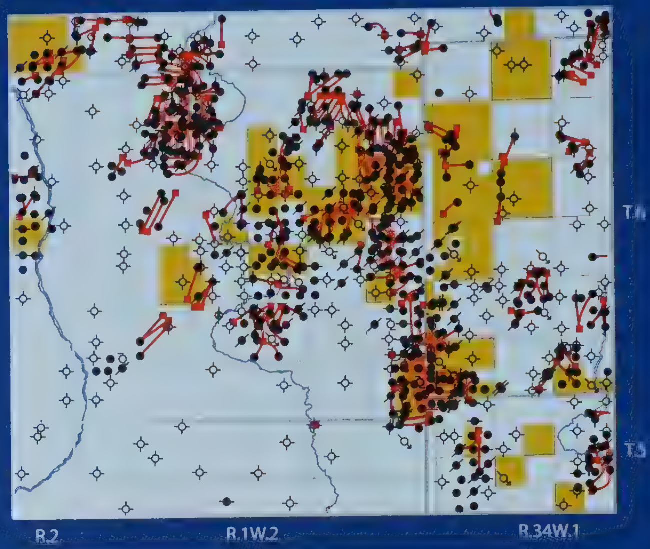
Queensdale has been a core area for the Trust since 2001 and continues to be an important property in Southeast Saskatchewan, where drilling during 2004 resulted in 6 (4.3 net) wells. Queensdale provides exploitation upside, based on an extensive 3D seismic database that allows the Trust to define reservoir structure and identify potential down-spacing and development opportunities.

At Handsworth, a property acquired through the purchase of Kinwest Resources in 2002, a technical review has indicated the potential to increase production and reserves through new horizontal drilling and re-entries. APF plans to drill two 100% working interest wells during 2005, targeting the Alida formation.

APF's Star Valley assets currently produce from the Alida formation. The Trust plans to drill three Kisbey locations during 2005. The Kisbey overlies the Alida and is believed to be a separate zone, based on a well drilled in 2004. Results from this well indicated a significant opportunity for APF's structurally higher lands.

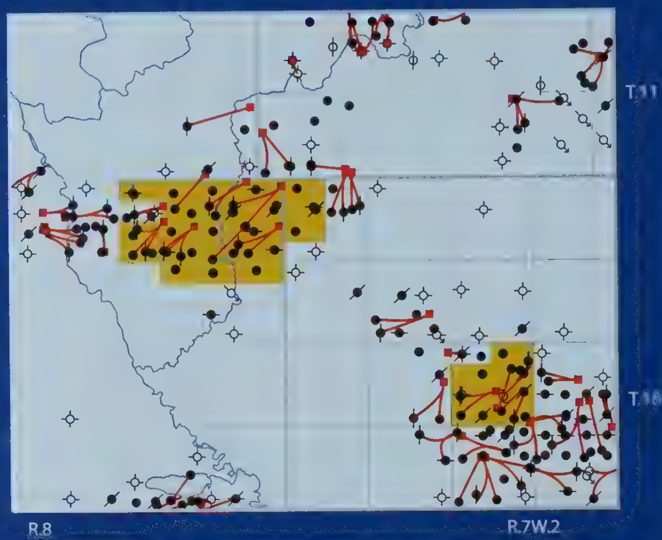
QUEENSDALE

- Light oil property
- Average working interest: 89%
- Operated: 55%
- Net undeveloped acres: 3,500
- Proved plus probable reserves: 1,255 mboe
- 2004 average production: 800 boe/d



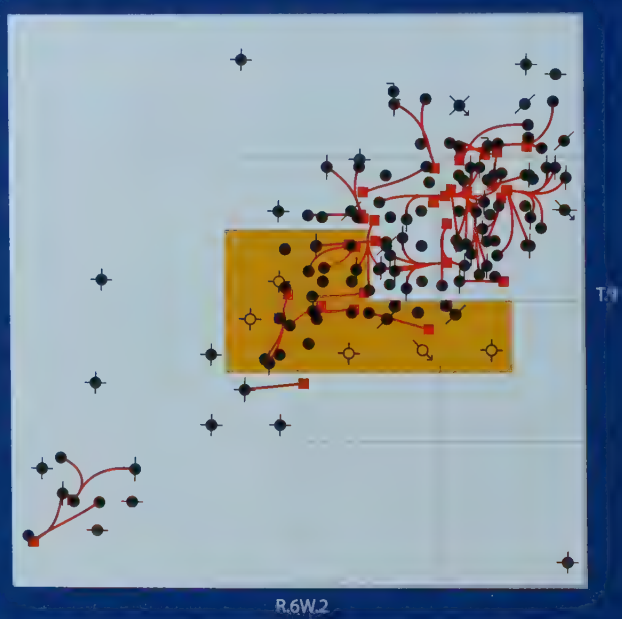
[illegible]WORTH

- Light/medium oil property
- Average working interest: 99%
- Operated: 100%
- Proved plus probable reserves: 745 mboe
- 2004 average production: 170 boe/d



[illegible] VALLEY

- Light oil property
- Average working interest: 55%
- Operated: 68%
- Net undeveloped acres: 378
- Proved plus probable reserves: 360 mboe
- 2004 average production: 100 boe/d



MAP LEGEND

Gas	Oil
Suspended gas	Suspended oil
Abandoned gas	Abandoned oil
Horizontal well leg	Dry and abandoned

SOUTHERN BUSINESS UNIT

KEY PROPERTIES: **Countess, Robsart, Wayne-Rosedale, Retlaw, Carmangay**

TARGET FORMATIONS: **Belly River, Milk River, Medicine Hat, Second White Specks, Barons, Bow Island, Basal Colorado, Mannville, Glauconitic, Sunburst**

UNDEVELOPED ACREAGE: **369,567 (165,899 net)**

2005 CAPITAL BUDGET

DRILLING & DEVELOPMENT:	**$8.0 million**
LAND & SEISMIC:	**$2.0 million**
TOTAL:	**$10.0 million**

2004 DRILLING RESULTS	Oil	Gas	Other	Dry	Total
Gross	7	101	1	0	109
Net	1.6	53.2	0.5	0.0	55.3

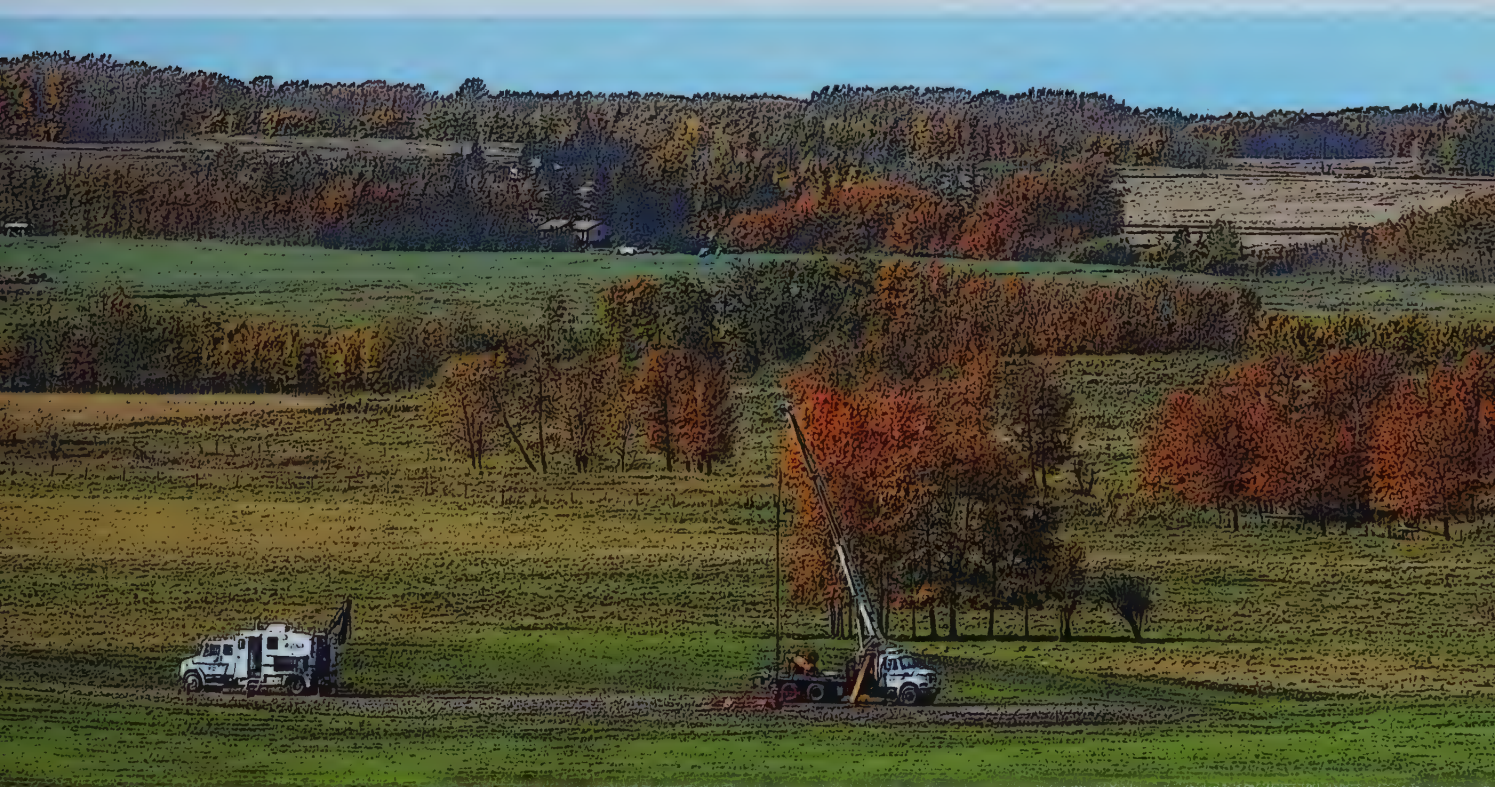
Shallow natural gas deposits largely characterize APF's Southern assets. Production during the fourth quarter of 2004 averaged 3,800 boe/d comprised of 500 bbls/d of liquids and 19,800 mcf/d of gas.

APF invested $19.5 million on development projects and drilled 109 (55.34 net) wells during 2004. While a significant portion of the activity focused on the Countess assets, the Trust also actively drilled for both oil and gas at Carmangay, Craigmyle, Enchant, Leahurst, Retlaw and Turin. These properties were acquired with the Nycan Energy transaction in April 2003. The 100% gas weighted Robsart properties were acquired as part of Great Northern, adding over 600 mboe of reserves to APF's proved plus probable total. The drilling of 3 (1.5 net) wells on these properties replaced 98% of the 167 boe/d of production.

In addition to shallow gas, APF holds deeper rights on a number of its properties, including Countess. Continued drilling success on these lands resulted in 83 (48.9 net) shallow and deep wells being drilled during the fourth quarter of the year. APF established its initial platform in this area in 1996 and has subsequently added both production and reserves annually. Formations targeted at Countess are primarily the Medicine Hat/Milk River at an average depth of 550 meters. During 2005, APF will continue to build on its success at Countess, with plans to drill 39 (34.5 net) wells. Deeper targets will continue to be pursued based on the success enjoyed in 2004.

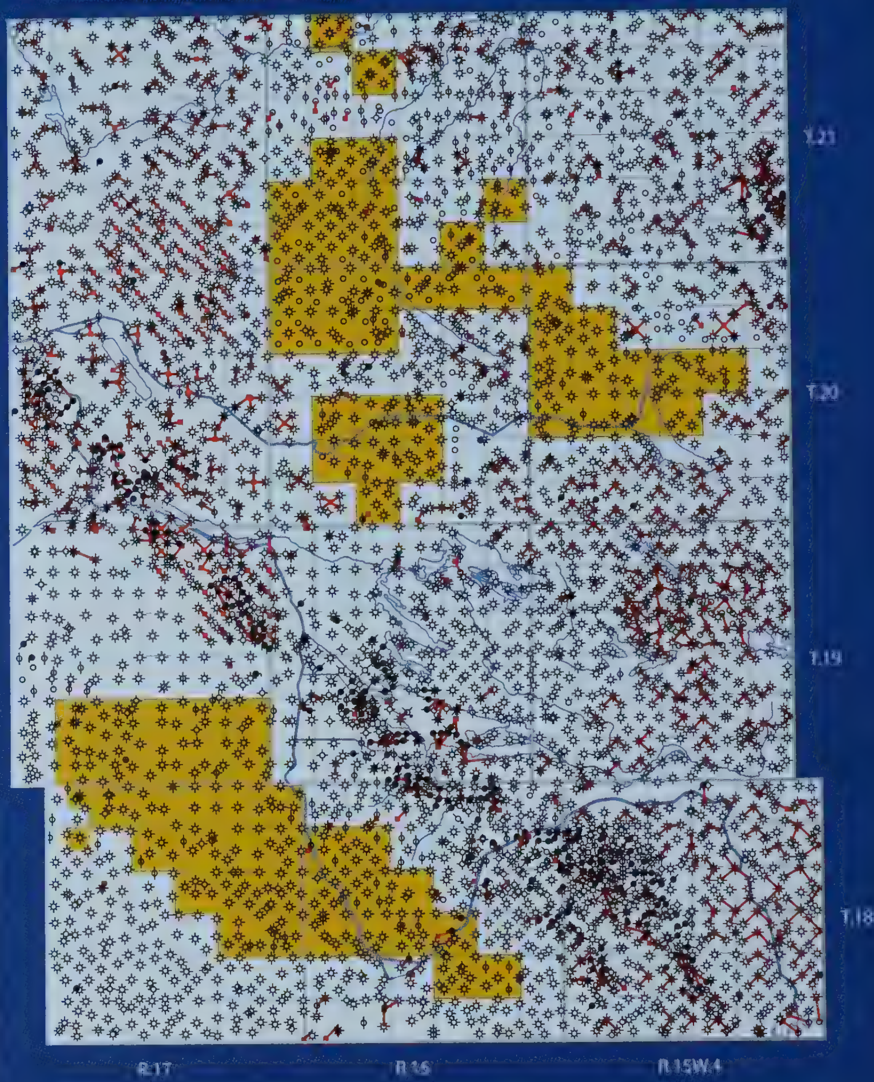
APF successfully drilled 6 (2.0 net) wells in 2004 and shot a 3D seismic program at Carmangay targeting the Second White Specks, Barons, Bow Island, and Sunburst formations. During 2005, APF will invest another $1.0 million drilling additional wells based on the 3D seismic interpretation.

The Southern properties have relatively low drilling costs and APF's extensive undeveloped land position has enabled multi-well drilling projects every year since inception.



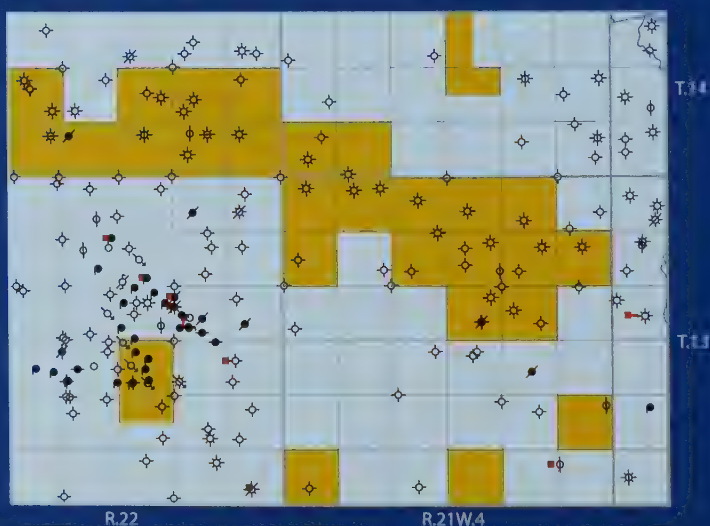
COUNTESS

- Shallow gas property
- Average working interest: 86%
- Operated: 95%
- Net undeveloped acres: 400
- Proved plus probable reserves: 7,500 mboe
- 2004 average production: 1,700 boe/d



CARMANGAY

- Shallow gas and oil property
- Average working interest: 52%
- Operated: 77%
- Net undeveloped acres: 9,300
- Proved plus probable reserves: 290 mboe
- 2004 average production: 90 boe/d



MAP LEGEND

- Gas
- Suspended gas
- Abandoned gas
- Oil
- Suspended oil
- Abandoned oil
- Dry and abandoned

CENTRAL BUSINESS UNIT

KEY PROPERTIES: **Innisfail, Wood River, Millet, Epping, Lone Rock, Cadogan**

TARGET FORMATIONS: **Edmonton Sand, Belly River Sand, Ellerslie Sand, Viking, Mannville, Pekisko, Wabamun, Nisku, Leduc**

UNDEVELOPED ACREAGE: **285,120 (116,105 net)**

2005 CAPITAL BUDGET

DRILLING & DEVELOPMENT:	**$11.4 million**
LAND & SEISMIC:	**$1.0 million**
TOTAL:	**$12.4 million**

2004 DRILLING RESULTS	Oil	Gas	Other	Dry	Total
Gross	1	21	0	0	22
Net	0.2	12.0	0.0	0.0	12.2

The Central Business Unit saw significant growth opportunities during 2004, driven primarily by the acquisition of Great Northern. Production averaged 7,100 boe/d during the fourth quarter, comprised of 3,400 bbls/d of liquids and 22,700 mcf/d of gas.

APF drilled 22 (12.2 net) wells on capital spending of $12.0 million in 2004. Drilling on conventional oil and gas properties added 900 boe/d of production and approximately 700 mboe of proved plus probable reserves. The Trust was active at crown sales throughout the year, acquiring undeveloped land adjacent to APF properties. Programs at Innisfail and Wood River accounted for 10 (8.6 net) of the wells drilled with another 25 locations identified for 2005.

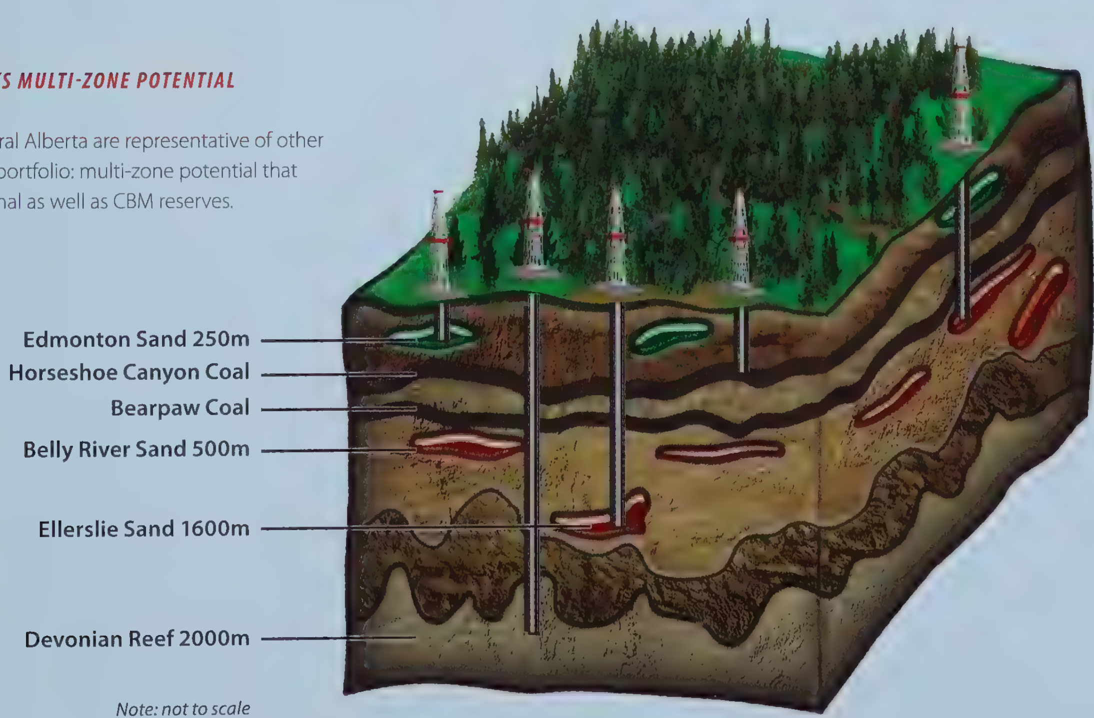
Heavy oil activity will continue at the Trust's Epping, Lone Rock and Cadogan properties located along the eastern edge of the Alberta border. With 13 (11.0 net) wells planned for 2005, APF will sharply increase activity over 2004. Despite heavy oil price differentials, continued strength in crude prices has resulted in favorable netbacks.

APF's Innisfail and Wood River holdings were acquired as part of the Great Northern transaction in 2004. Drilling activity at Innisfail targets shallow Edmonton Sand gas and deeper Pekisko and Leduc oil, while Wood River's primary producing zones are the Belly River and Ellerslie. The Wood River assets are prospective for both conventional and coalbed methane production in multiple zones. The Trust anticipates investing $5.3 million drilling 11 (6.5 net) conventional wells on these properties in 2005.

The 2005 capital program for the Central Business Unit is expected to total $12.4 million, comprised of $11.4 million for drilling and completions and $1.0 million for land and seismic. Activity will focus on internal opportunities present at Innisfail, Wood River and the Epping/Lone Rock heavy oil properties.

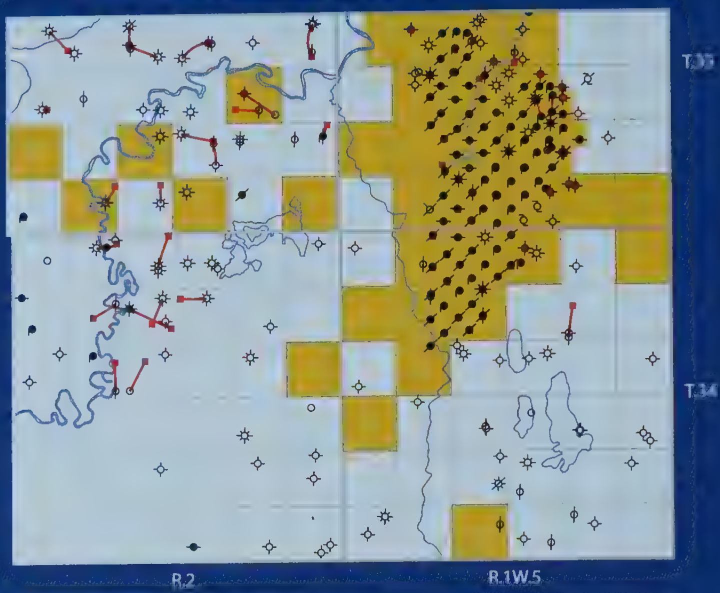
CENTRAL ALBERTA'S MULTI-ZONE POTENTIAL

APF's assets in Central Alberta are representative of other properties in APF's portfolio: multi-zone potential that includes conventional as well as CBM reserves.



INNISFAIL

- Natural gas and oil property
- Average working interest: 50% (Innisfail Unit 97%)
- Operated: 56%
- Net undeveloped acres: 11,500
- Proved plus probable reserves: 7,500 mboe
- 2004 average production: 1,100 boe/d

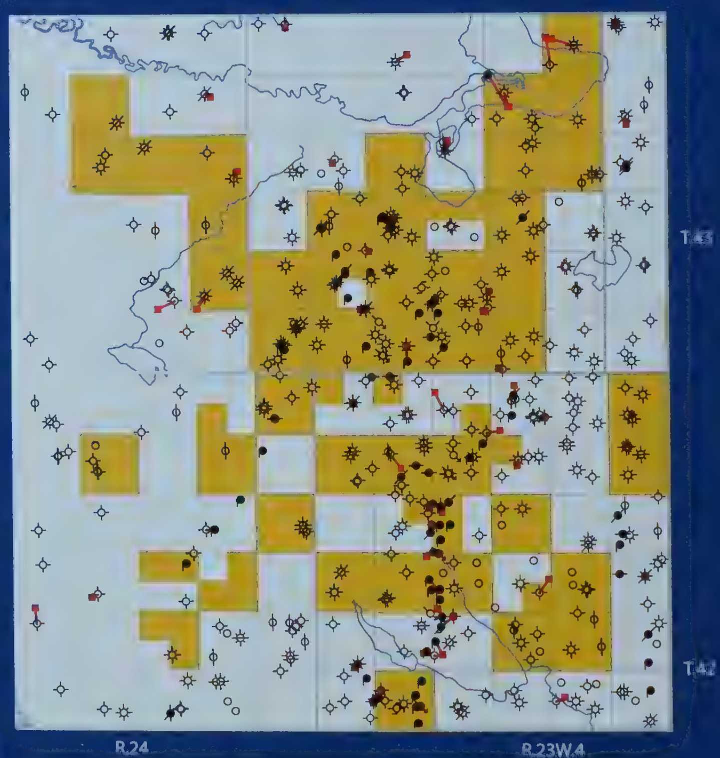


[illegible] / LONE ROCK

- Heavy oil property
- Average working interest: 50%
- Operated: 53%
- Net undeveloped acres: 2,300
- Proved plus probable reserves: 1,400 mboe
- 2004 average production: 360 boe/d

WOOD RIVER

- Natural gas and oil property
- Average working interest: 49%
- Operated: 65%
- Net undeveloped acres: 5,300
- Proved plus probable reserves: 2,800 mboe
- 2004 average production: 700 boe/d



MAP LEGEND

- Gas
- Suspended gas
- Abandoned gas
- Oil
- Suspended oil
- Abandoned oil
- Dry and abandoned

WESTERN BUSINESS UNIT

KEY PROPERTIES: **Leaman, Paddle River, Swan Hills, Redwater, Pembina, Sakwatamau**

TARGET FORMATIONS: **Edmonton, Belly River, Cardium, Upper and Lower Mannville, Nordegg, Swan Hills**

UNDEVELOPED ACREAGE: **319,200 (162,034 net)**

2005 CAPITAL BUDGET

DRILLING & DEVELOPMENT:	**$5.8 million**
LAND & SEISMIC:	**$3.3 million**
TOTAL:	**$9.1 million**

2004 DRILLING RESULTS	Oil	Gas	Other	Dry	Total
Gross	10	13	1	3	27
Net	0.6	5.9	0.0	2.0	8.5

APF's Western Business Unit properties offer a combination of opportunities for oil and natural gas. During the fourth quarter of 2004, the Trust averaged 3,700 boe/d comprised of 1,500 boe/d of liquids and 13,000 mcf/d of natural gas volumes.

Development spending of $11.1 million during 2004 resulted in 27 (8.5 net) wells being drilled. The majority of 2004 activity was focused at Swan Hills and Paddle River.

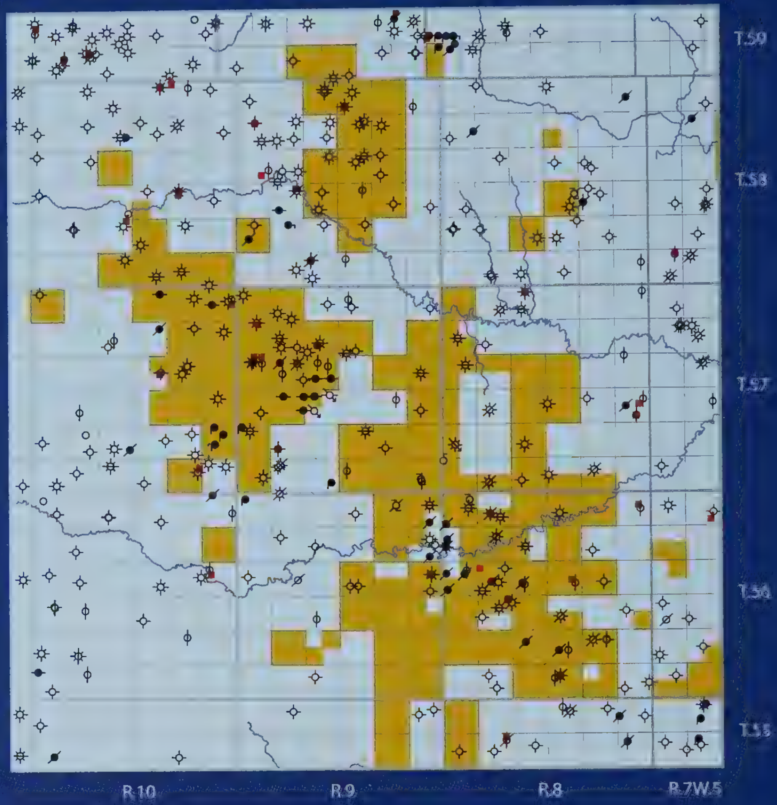
Swan Hills Unit No. 1 is a world-class light oil pool which enjoys a long reserve life index of 19 years. During 2004, APF participated in the drilling of 6 (0.15 net) wells at Swan Hills, including one injection well. The interest in this property was acquired in 2003 and seven new locations have been identified for 2005. Extensive reservoir modeling has shown incremental reserves will be gained with a water flood program, with potential for tertiary recovery through a miscible flood.

At Paddle River, the Trust drilled 3 (1.0 net) wells which tested the Edmonton and Belly River, where additional drilling opportunities exist. APF has been active at Paddle River since acquiring the assets in 2002.

In total, 2005 capital of $9.8 million has been allocated to projects at Leaman, Swan Hills and other properties. This includes $3.3 million for shooting seismic that the Trust plans to utilize in identifying new locations.

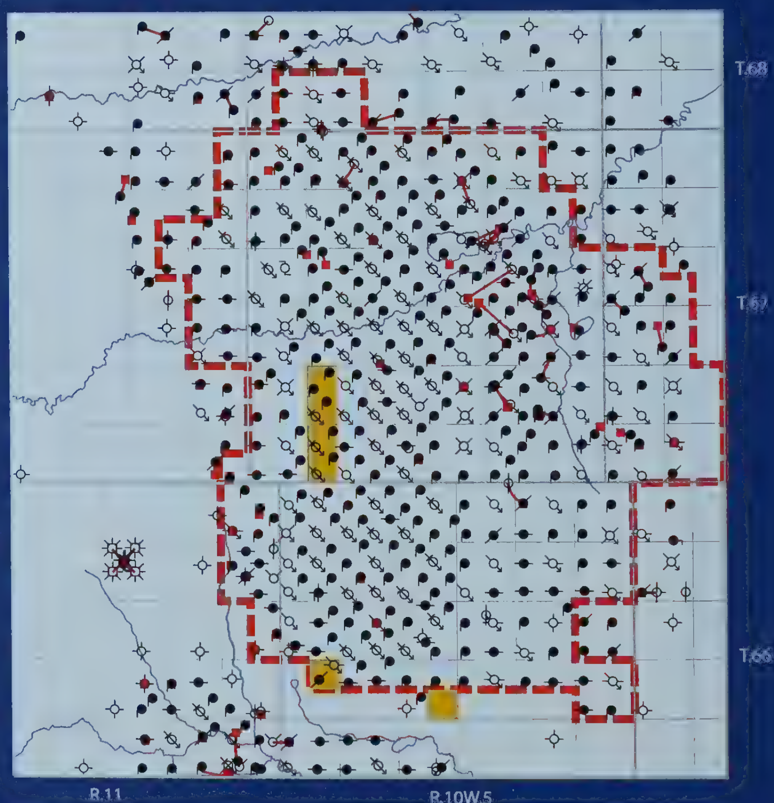
LEAMAN

- Natural gas property
- Average working interest: 62%
- Operated: 60%
- Net undeveloped acres: 31,000
- Proved plus probable reserves: 676 mboe
- 2004 average production: 440 boe/d



SWAN HILLS

- Enhanced oil recovery (water flood) property
- Average working interest: 2.6%
- Non-operated
- Net undeveloped acres: 190
- Proved plus probable reserves: 2,600 mboe
- 2004 average production: 378 boe/d



Swan Hills Unit No.1

MAP LEGEND

- Gas
- Suspended gas
- Abandoned gas
- Oil
- Suspended oil
- Abandoned oil
- Dry and abandoned

COALBED METHANE BUSINESS UNIT

KEY PROPERTIES: **Alberta: Bittern Lake, Doris-Corbett, Knellar, Stettler, Trochu-Rowley, Wetaskiwin, Wood River**
Wyoming: Big Bend, Hensley Draw, Kane, North Carson

TARGET FORMATIONS: **Alberta: Edmonton Formation (Horseshoe Canyon Member), Upper Mannville**

Wyoming: Fort Union Formation (Big George, Wyodak, Cook, Canyon, Wall, Pawnee seams)

UNDEVELOPED ACREAGE: **Alberta: 116,104 (65,970 net), Wyoming: 21,793 (10,801 net)**

2005 CAPITAL BUDGET

DRILLING & DEVELOPMENT:	**Alberta $15.3 million**
	Wyoming $4.5 million
LAND & SEISMIC:	**Alberta $0.4 million**
TOTAL:	**$20.1 million**

2004 DRILLING RESULTS	CBM	Other	Dry	Total
Gross	104	2	0	106
Net	42.2	1.7	0.0	43.9

APF is active in three CBM plays. The acquisition of CanScot Resources in 2003 brought with it CBM production in the Powder River Basin ("PRB") of Wyoming and prospects for Upper Mannville production in Western Alberta. During 2004, through the acquisition of Great Northern and additional land purchases, APF established a highly prospective position along the Horseshoe Canyon ("HSC") fairway of Alberta.

Since acquiring its initial CBM position, APF's daily CBM production has increased from 500 mcf to 1,800 mcf currently. Fourth quarter CBM production averaged 1,500 mcf/d.

At the end of 2003, APF's proved plus probable CBM reserves amounted to 1,475 mboe, with a net present value ("NPV") discounted at 10% of $3.5 million. The December 31, 2004 evaluation increased proved plus probable reserves to 4,268 mboe and a value of $31.2 million.

In 2004, CBM drilling activity focused on the HSC. These coals produce natural gas at shallow depths with no associated water. As at December 31, 2004, the industry had drilled over 2,500 HSC wells with total current production of approximately 150 mmcf/d, making this play one of the largest new gas discoveries in Western Canada in decades. During the year, several pilot projects were initiated along a 100-kilometer trend in order to evaluate APF's extensive land position. Based upon very encouraging results, APF plans to accelerate its activity, primarily at Wood River, Wetaskiwin and Bittern Lake. APF acquired 15,095 net acres of land in the area at crown sales throughout the year, for a total cost of $5.1 million. The Trust was also assigned 5.5 bcf of proved plus probable HSC reserves at December 31, 2004, based on initial pilot testing. The Trust plans to aggressively expand its HSC program in 2005 with the drilling of 56 (41 net) wells. In addition, gas compression and processing facilities are being constructed to accommodate the incremental production volumes.

APF has focused its HSC drilling efforts at Wood River and Bittern Lake. Of the 14 (9.4 net) wells drilled during 2004, seven were tied-in by year-end with the remainder to be tied-in during the first half of 2005. APF plans to drill 56 (41.4 net) HSC wells during 2005, at a total cost of $15.3 million. The Trust has applied for holding permits that would increase well density to four wells per section on most of its Alberta CBM lands, providing further development opportunities.

Properties at Bittern Lake were acquired as a result of a grass-roots exploration effort in 2004. Results from an initial test well were used to evaluate a large posting of crown land that was successfully acquired during the year. Three wells drilled on the acquired lands during 2004 were successful, leading to full-scale development plans for 2005.

APF's Wood River property produces both conventional and CBM volumes. The Trust drilled 8 (4.3 net) CBM wells and 1 (1.0 net) re-completion at a cost of $1.2 million during 2004. Three of the wells are operated with 100% working interest and all were tested prior to year-end. Two of these wells are on production at a combined rate of approximately 400 mcf/d with the third awaiting tie-in. APF has identified 83 (44.6 net) additional CBM locations on its existing land inventory at Wood River. The drilling and tie-in of 18 (8.5 net) wells has been budgeted for 2005 at an estimated cost of $3.3 million.

APF participated in drilling 5 (3.1 net) CBM wells on its Southern Business Unit properties, all of which targeted the

HSC formation. Three of these wells were completed and producing during the first half of 2004 and one awaits tie-in. The final well was drilled at Craigmyle during the fourth quarter and will be completed in early 2005. APF plans to continue drilling for CBM within this area during 2005, having identified seven new locations.

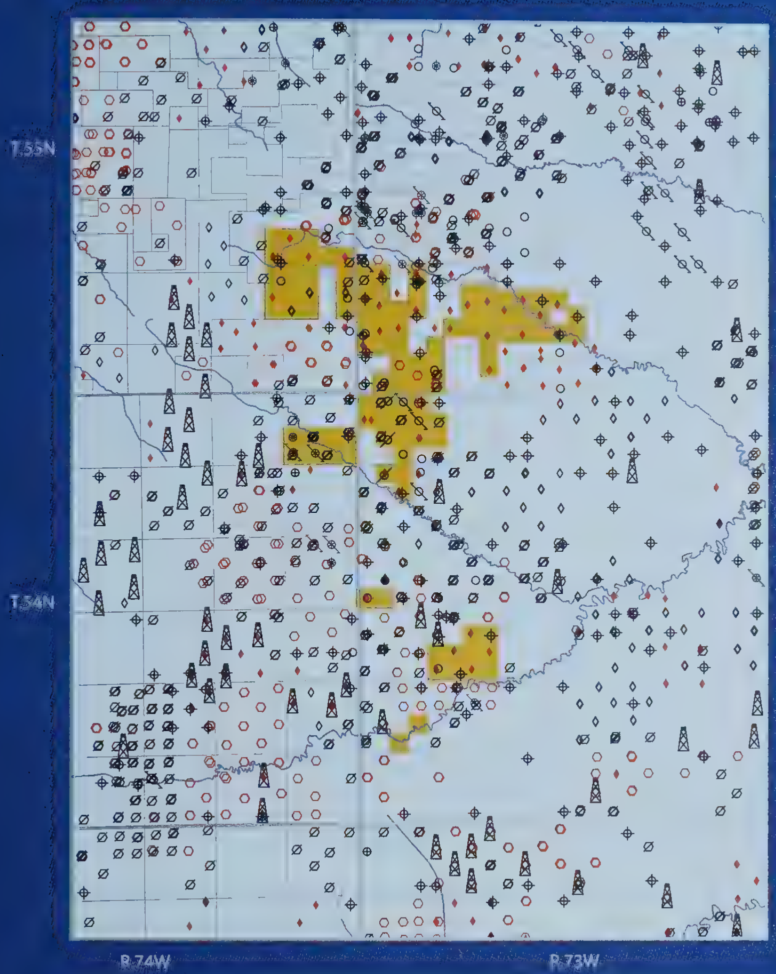
Operations are continuing with the Upper Mannville pilot project at the Doris and Corbett properties. The de-watering process from the first well began in March of 2003. During 2004, 6 (2.1 net) wells were drilled as the project moved into Phase II. De-watering is continuing with no commercial production volumes from the project to date. Activity on lands surrounding APF's projects remains vigorous with nine horizontal wells licensed on adjacent lands during 2004. This demonstrates continued optimism regarding the reserve potential in the region and a willingness to apply different technologies to realize the benefits. APF remains confident in these assets. The Trust has farmed out development opportunities on several sections to minimize the impact on cash resources while still participating in the upside potential.

Wyoming

Drilling success and a maturing development program have fueled expansion of CBM projects on APF's Wyoming properties. The majority of these lands were acquired with the purchase of CanScot in 2003.

The Powder River Basin ("PRB") has been producing CBM at commercial rates since 1998. Drilling metrics are highly attractive with wells costing, on average, U.S.$100,000 to drill, complete and tie-in. Big Bend, Kane, and North Carson accounted for the bulk of the Trust's 2004 drilling activity. During the year, APF acquired the interests of two partners, increasing its working interest to 86.7% at Big Bend, approximately 27% at Kane and 25% at North Carson. A total of 81 (29.4 net) wells were drilled on the Wyoming properties during 2004 and another 77 (31.7 net) are planned for 2005.

The rate of drilling and production increase in the PRB is expected to continue in 2005 with the allocation of $4.5 million for capital expenditures. APF plans to accelerate the conversion of undeveloped to producing reserves through its drilling program, and the realization of production from wells that are currently de-watering.

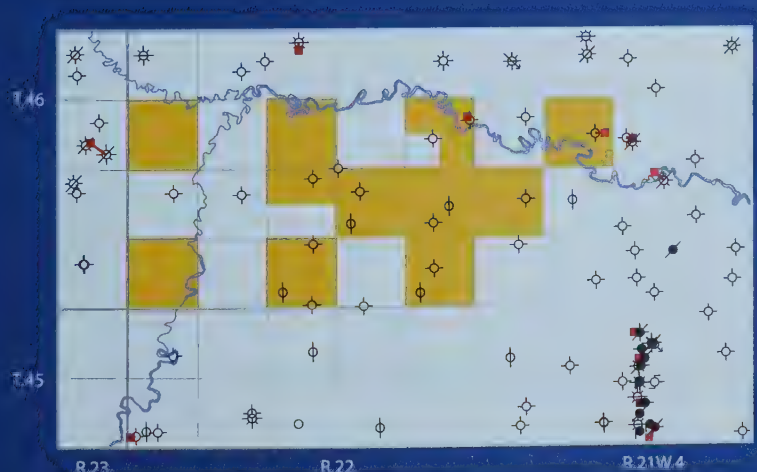


NORTH CARSON

- Coalbed methane property – Wyoming
- Average working interest: 20%
- Non-operated
- Proved plus probable reserves: 375 mboe

NORTH CARSON MAP LEGEND

- Producing CBM
- Shut-in CBM
- Approved Permits
- Permits Waiting
- Drilling CBM
- Expired CBM Permit
- Active Water Injection Well



BITTERN LAKE

- Coalbed methane property – Central Alberta
- Average working interest: 100%
- Operated: 100%
- Net undeveloped acres: 6,404
- Proved plus probable CBM reserves: 453 mboe

MAP LEGEND

- Gas
- Suspended gas
- Abandoned gas
- Oil
- Suspended oil
- Abandoned oil
- Dry and abandoned

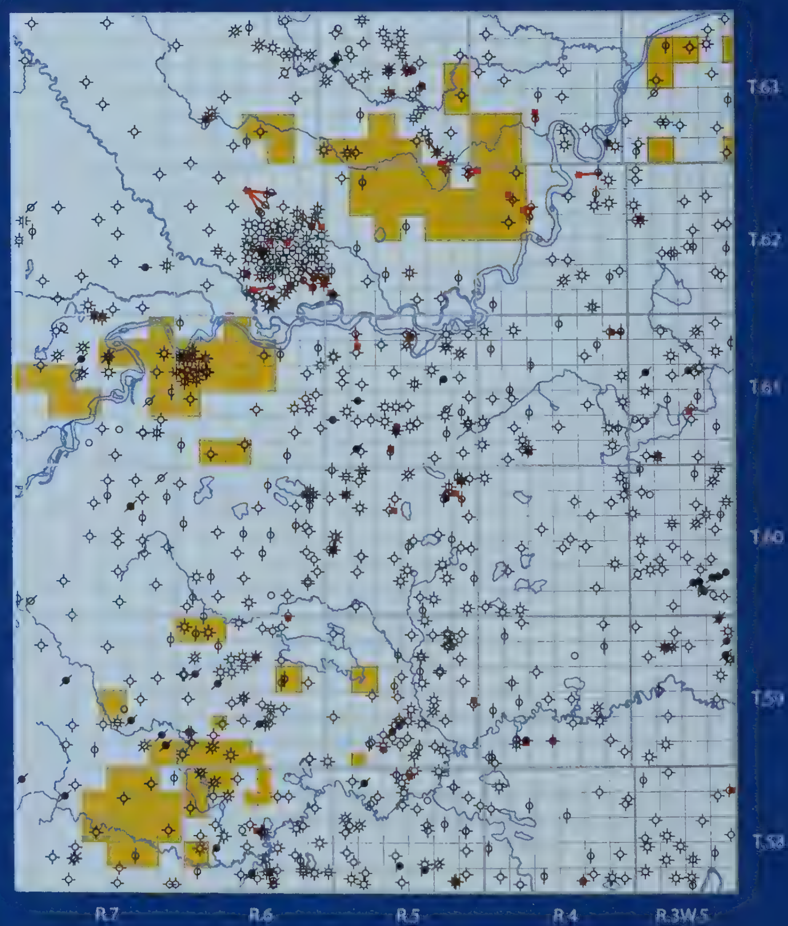
WOOD RIVER

- Coalbed methane and natural gas property – Central Alberta
- Average working interest: 49%
- Operated: 65%
- Net undeveloped acres: 5,300
- Proved plus probable CBM reserves: 395 mboe

DORIS/CORBETT

- Coalbed methane property – Western Alberta
- Average working interest: 68%
- Operated: 90%
- Net undeveloped acres: 25,250

As at December 31, 2004, no reserves had been assigned to these properties. Reserves can be assigned once commercial production is achieved. Any volumes of gas currently produced are utilized in operating the facility for de-watering purposes.



MAP LEGEND

- Gas
- Suspended gas
- Abandoned gas
- Oil
- Suspended oil
- Abandoned oil
- Dry and abandoned

ACTIVE CAPITAL PROGRAM

Drilling Activity

Years ended December 31,	2004		2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	37	12.4	60	19.4	40	12.0	40	8.9
Gas	135	71.1	80	40.2	62	33.0	33	31.3
CBM	104	42.2	19	4.4	–	–	–	–
Other	4	2.3	5	0.8	7	1.7	1	0.1
Dry and abandoned	4	3.0	–	–	–	–	2	2
Total	284	131.0	164	64.8	109	46.7	76	42.2
Success Rate		98%		100%		100%		95%

Capital Expenditures

The following table summarizes APF's capital expenditures for the years indicated.

Years ended December 31,	2004	2003	2002	2001
($000)				
Corporate and asset acquisitions	301,435	164,550	90,101	105,717
Land acquisitions	10,344	2,310	616	239
Seismic	4,561	1,070	497	208
Drilling and completion	41,449	24,287	15,890	12,490
Production facilities	11,222	7,749	3,684	3,340
Head office	1,203	494	908	(52)
Subtotal	370,214	200,460	111,696	121,942
Dispositions	(505)	(9,284)	(10,569)	(6,903)
Net capital expenditures	369,709	191,176	101,127	115,039

FINDING AND DEVELOPMENT COSTS ("F&D")

Proved ($000)	2004	2003	2002	2001
Total F&D	67,576	33,601	21,595	16,225
Change in future development capital	24,857	7,399	7,915	4,479
Total	92,433	41,000	29,510	20,704
Net reserve additions (mboe)	5,541	423	3,773	2,710

($/boe except recycle ratio values)	2004	2003	2002	2001
F&D cost	$16.68	$96.93	$7.82	$7.64
Operating netback	$22.56	$22.10	$17.83	$20.42
Recycle ratio	1.35	0.23	2.28	2.67
Rolling three year average F&D costs	$16.73	$13.21	$7.43	$6.83
Rolling three year average netback	$20.83	$20.12	$19.84	$17.27
Rolling three year average recycle ratio	1.24	1.52	2.67	2.53

FINDING, DEVELOPMENT AND ACQUISITION COSTS ("F,D&A")

Proved ($000)	2004	2003	2002	2001
Total F,D&A	67,576	33,601	21,595	16,225
Change in future development capital	24,857	7,399	7,915	4,479
Net acquisitions	300,930	154,639	79,532	98,814
Total	393,363	195,639	109,042	119,518
Net reserve additions (mboe)	18,983	7,084	11,384	9,900

($/boe except recycle ratio values)	2004	2003	2002	2001
F,D&A costs	$20.72	$27.62	$9.58	$12.07
Operating netback	$22.56	$22.10	$17.83	$20.42
Recycle ratio	1.09	0.80	1.86	1.69
Rolling three year average F,D&A costs	$18.64	$14.95	$10.51	$11.69
Rolling three year average netback	$20.83	$20.12	$19.84	$17.27
Rolling three year average recycle ratio	1.12	1.35	1.89	1.48

The aggregate of the exploration and development costs incurred in the most recent financial year end and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

FINDING AND DEVELOPMENT COSTS

Proved plus probable* ($000)	2004	2003	2002	2001
Total F&D	67,576	33,601	21,595	16,225
Change in future development capital	40,752	27,048	11,525	5,625
Total	108,328	60,649	33,120	21,850
Net reserve additions (mboe)	5,423	3,002	4,054	2,690
($/boe except recycle ratio values)				
F&D cost	$19.98	$20.20	$8.17	$8.12
Operating netback	$22.56	$22.10	$17.83	$20.42
Recycle ratio	1.13	1.09	2.18	2.51
Rolling three year average F&D costs	$16.19	$11.86	$7.88	$9.49
Rolling three year average netback	$20.83	$20.12	$19.84	$17.27
Rolling three year average recycle ratio	1.29	1.68	2.52	1.82

FINDING, DEVELOPMENT AND ACQUISITION COSTS

Proved plus probable* ($000)	2004	2003	2002	2001
Total F,D&A	67,576	33,601	21,595	16,225
Change in future development capital	40,752	27,048	11,525	5,625
Net acquisitions	300,930	157,576	79,532	98,814
Total	409,258	218,225	112,652	120,664
Net reserve additions (mboe)	24,271	12,881	13,064	10,740
($/boe except recycle ratio values)				
F,D&A costs	$16.86	$16.94	$8.62	$11.24
Operating netback	$22.56	$22.10	$17.83	$20.42
Recycle ratio	1.34	1.30	2.07	1.82
Rolling three year average F,D&A costs	$14.74	$12.31	$9.59	$11.66
Rolling three year average netback	$20.83	$20.12	$19.84	$17.27
Rolling three year average recycle ratio	1.41	1.63	2.07	1.48

* Proved plus half probables were used prior to 2003

The aggregate of the exploration and development costs incurred in the most recent financial year end and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

RESERVES

All of APF's conventional Canadian reserves were evaluated by Gilbert Laustsen Jung Associates Ltd. ("GLJ"), while all coalbed methane ("CBM") properties were evaluated by Sproule Associates Limited ("Sproule"). Both reports were prepared effective December 31, 2004. All reserves were evaluated in accordance with NI 51-101.

SUMMARY OF RESERVES As at December 31, 2004	Natural gas (mmcf)	Light & medium oil (mbbl)	Heavy oil (mbbl)	NGL's (mbbl)	Total (mboe) (1)
Proved					
Developed producing	98,935	15,483	1,106	1,941	35,019
Developed non-producing	11,574	486	479	116	3,009
Undeveloped	15,224	2,169	154	130	4,989
Total Proved	125,733	18,137	1,738	2,186	43,017
Probable	43,679	6,718	1,085	634	15,716
Proved plus probable	169,412	24,855	2,823	2,820	58,733

Columns may not add due to rounding

APF's reserves were evaluated using the GLJ January 1, 2005 price forecast. The net present values shown below do not necessarily represent the fair market value of the reserves.

NET PRESENT VALUE OF FUTURE NET REVENUE BEFORE INCOME TAXES As of December 31, 2004 (based on forecast pricing and costs, $000)	Reserve life index (years)*	8%	10%	12%
Proved				
Developed producing	5.3	459,323	432,829	410,030
Developed non-producing		34,399	31,839	29,655
Undeveloped		31,987	27,684	24,060
Total proved	6.5	525,709	492,352	463,745
Probable		142,832	126,716	113,524
Proved plus probable	8.9	668,541	619,067	577,269

Net present values include allocations for asset abandonment

*As calculated by APF using 18,000 boe/d

NET ASSET VALUE OF PROVED PLUS PROBABLE RESERVES As of December 31, 2004 (based on forecast pricing and costs, $000)	8%	10%	12%
Net present value	668,541	619,067	577,269
Land	64,735	64,735	64,735
Seismic	20,208	20,208	20,208
Bank debt	(169,000)	(169,000)	(169,000)
Convertible debentures	(48,846)	(48,846)	(48,846)
Working capital	(11,991)	(11,991)	(11,991)
Total net asset value	523,647	474,173	432,375
Units outstanding	58,845	58,845	58,845
Net asset value per unit ($)	8.90	8.06	7.35

GLJ commodity price assumptions, effective January 1, 2005 are as follows:

COMMODITY PRICES Year	WTI oil ($U.S./bbl)	Foreign exchange ($U.S./$Cdn.)	Heavy oil ($Cdn./bbl)	Light oil ($Cdn./bbl)	AECO gas ($Cdn./mmbtu)
2005	42.00	1.2195	27.50	50.25	6.60
2006	40.00	1.2195	28.50	47.75	6.35
2007	38.00	1.2195	28.75	45.50	6.15
2008	36.00	1.2195	27.25	43.25	6.00
2009	34.00	1.2195	25.50	40.75	6.00
2010	33.00	1.2195	24.75	39.50	6.00
2011	33.00	1.2195	24.75	39.50	6.00
2012	33.00	1.2195	24.75	39.50	6.00
2013	33.50	1.2195	24.75	40.00	6.10
2014	34.00	1.2195	25.50	40.75	6.20
2015	34.50	1.2195	25.75	41.25	6.30
Escalate thereafter	2%/yr	–	2%/yr	2%/yr	2%/yr

The following table contains a reconciliation of APF's Company Interest Reserves(1) on a proved plus probable basis for the most recently completed calendar year.

RECONCILIATION OF PROVED PLUS PROBABLE RESERVES	Natural gas (mmcf)	CBM (mmcf)	Light & medium oil (mbbl)	Heavy oil (mbbl)	NGL's (mbbl)	Total (mboe)(2)
Reserves at December 31, 2003	90,347	8,850	19,634	3,003	1,151	40,322
Extensions	1,085	–	458	52	8	699
Improved recovery	16,188	11,820	415	1	40	5,124
Technical revisions	34	2,024	(1,424)	58	287	(737)
Discoveries	471	–	108	–	3	189
Acquisitions	53,476	3,312	7,777	155	1,608	19,004
Dispositions	–	–	(8)	–	–	(8)
Production	(17,798)	(397)	(2,104)	(447)	(277)	(5,860)
Reserves at December 31, 2004	143,804	25,608	24,855	2,823	2,820	58,733

(1) Company Interest Reserves are defined as working interest (before the deduction of royalties) plus royalty interest reserves.

(2) BOE's may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio for natural gas of 6 Mcf: 1 bbl has been used which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

LAND HOLDINGS

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Southern	313,229	149,961	391,360	176,700	704,589	326,661
Central	195,497	68,416	285,120	116,105	480,617	184,521
Western	212,264	79,726	319,200	162,034	531,464	241,760
Southeast Saskatchewan	40,988	25,215	234,400	63,040	275,388	88,555
Total	761,978	323,318	1,230,080	517,879	1,992,058	841,197

In addition to the Canadian oil and gas reserves, GLJ also valued APF's 517,879 acres of net undeveloped land at $64.7 million. The value was derived by reference to land sales proximate to APF's acreage, the applicable working interest and expiry profile. In addition, the Trust holds 10,801 net undeveloped acres in Wyoming to which no value has been assigned.

During 2004, APF acquired approximately 26,480 gross (20,113 net) acres of land through freehold acquisitions as well as crown sales. Most of the acreage is in close proximity to existing APF landholdings, including numerous parcels acquired along the HSC trend in South Central Alberta.

APF's objective is to accumulate an undeveloped land base which enables the Trust not only to increase production through exploitation and optimization but also through step-out drilling and pool extensions which ensures the asset base continues to grow, independent of merger and acquisition activity.

SEISMIC

APF's seismic database was independently evaluated by Boyd Exploration Consultants Ltd. at $20.2 million. Both 2D and 3D seismic is utilized by the Trust's operations group to identify structural anomalies leading to drilling opportunities.

CORPORATE REVIEW

Business Objectives

The goal of APF Energy Trust is to provide unitholders with high distributions while executing its full cycle business plan. To achieve this, the Trust must continually replace production and reserves, either through internal drilling and optimization initiatives or through accretive acquisitions.

Financings

APF completed its initial public offering for $35.0 million on December 16, 1996. Since then, the Trust has issued an additional 49.9 million units through offerings noted below, raising approximately $536.6 million in equity to fund growth and development initiatives. APF will continue to issue equity from time to time, to finance acquisitions and capital budget requirements.

On July 3, 2003, APF issued $50.0 million of 9.40 percent unsecured subordinated convertible debentures ("convertible debentures") for proceeds of $50.0 million ($47.7 million net of issue costs). Interest is paid semi-annually on January 31 and July 31 and the instruments mature on July 31, 2008.

The debentures are convertible at the holder's option into fully paid and non-assessable Trust units at any time prior to July 31, 2008, at a conversion price of $11.25 per Trust unit. The holder will receive accrued and unpaid interest up to and including the conversion date. The debentures are not redeemable by the Trust before July 31, 2006, except under certain circumstances. The convertible debentures become redeemable at $1,050 per convertible debenture, in whole or in part, after July 31, 2006 and redeemable at $1,025 after July 31, 2007 and before maturity.

EQUITY ISSUES

Type	Date	Unit price	Units (000)	Gross proceeds ($000)
IPO	Dec 1996	$10.00	3,500	35,000
New issue	Dec 1998	$8.00	2,260	18,080
New issue	Mar 2000	$7.30	1,223	8,928
New issue	Mar 2001	$10.00	3,301	33,010
Acquisition	Apr 2001	$10.05	902	9,065
New issue	Jun 2001	$11.50	3,050	35,075
Private placement	Oct 2001	$9.55	1,080	10,314
New issue	Feb 2002	$9.75	3,250	31,688
Acquisition	May 2002	$10.15	3,385	34,358
Acquisition	Feb 2003	$9.45	3,990	37,708
New issue	Apr 2003	$10.40	5,352	55,670
Acquisition	Sep 2003	$11.50	1,342	15,433
New issue	Feb 2004	$11.60	4,765	55,270
Acquisition	Jun 2004	$12.18	12,885	156,943
New issue	Sep 2004	$11.30	3,100	35,030
Total equity			53,385	571,568
Convertible debentures	Jul 2003	$1,000.00	50	50,000

Distributions are paid monthly to unitholders of record on the applicable record date. APF's record date is the last trading day of the month. In order to be a unitholder on the record date, units must have been purchased prior to the ex-distribution date, which is two trading days earlier. Key dates for 2005 are presented in this annual report and can be accessed on APF's website. Purchases of units which settle on or after the ex-distribution date are not eligible for that month's distribution, but will qualify for the next month's distribution. Payments are made to unitholders on the 15th of the following month (if the 15th day of the month falls on a holiday or weekend, the distribution is paid the next business day). Since inception, the Trust has distributed $15.84 per unit to December, 2004, or an average of $1.98 per year.

HISTORICAL DISTRIBUTIONS

Month	2004	2003	2002	2001	2000	1999	1998	1997
January	0.175	0.160	0.150	0.220	0.125	0.120	0.475	0.210
February	0.175	0.160	0.150	0.250	0.125	0.160	–	–
March	0.175	0.165	0.150	0.250	0.125	0.120	0.120	–
April	0.175	0.185	0.150	0.225	0.125	0.120	0.120	0.455
May	0.175	0.185	0.150	0.300	0.125	0.160	0.175	–
June	0.175	0.200	0.150	0.300	0.135	0.120	0.120	–
July	0.160	0.200	0.150	0.300	0.135	0.120	0.120	0.420
August	0.160	0.200	0.150	0.300	0.135	0.135	0.175	–
September	0.160	0.200	0.150	0.250	0.140	0.125	0.120	–
October	0.160	0.175	0.150	0.250	0.210	0.125	0.120	0.425
November	0.160	0.175	0.150	0.200	0.210	0.125	0.175	–
December	0.160	0.175	0.150	0.200	0.310	0.125	0.120	–
Total ($)	2.010	2.180	1.800	3.045	1.900	1.555	1.840	1.51
Cumulative ($)	15.84	13.83	11.65	9.85	6.805	4.905	3.35	1.51

KEY 2005 DISTRIBUTION DATES

Distribution payment date	Ex-distribution date	Record date
February 15, 2005	January 27, 2005	January 31, 2005
March 15, 2005	February 24, 2005	February 28, 2005
April 15, 2005	March 29, 2005	March 31, 2005
May 16, 2005	April 27, 2005	April 29, 2005
June 15, 2005	May 27, 2005	May 31, 2005
July 15, 2005	June 28, 2005	June 30, 2005
August 15, 2005	July 27, 2005	July 29, 2005
September 15, 2005	August 29, 2005	August 31, 2005
October 17, 2005	September 28, 2005	September 30, 2005
November 15, 2005	October 27, 2005	October 31, 2005
December 15, 2005	November 28, 2005	November 30, 2005
January 16, 2006	December 28, 2005	December 30, 2005

Distribution Reinvestment Plan

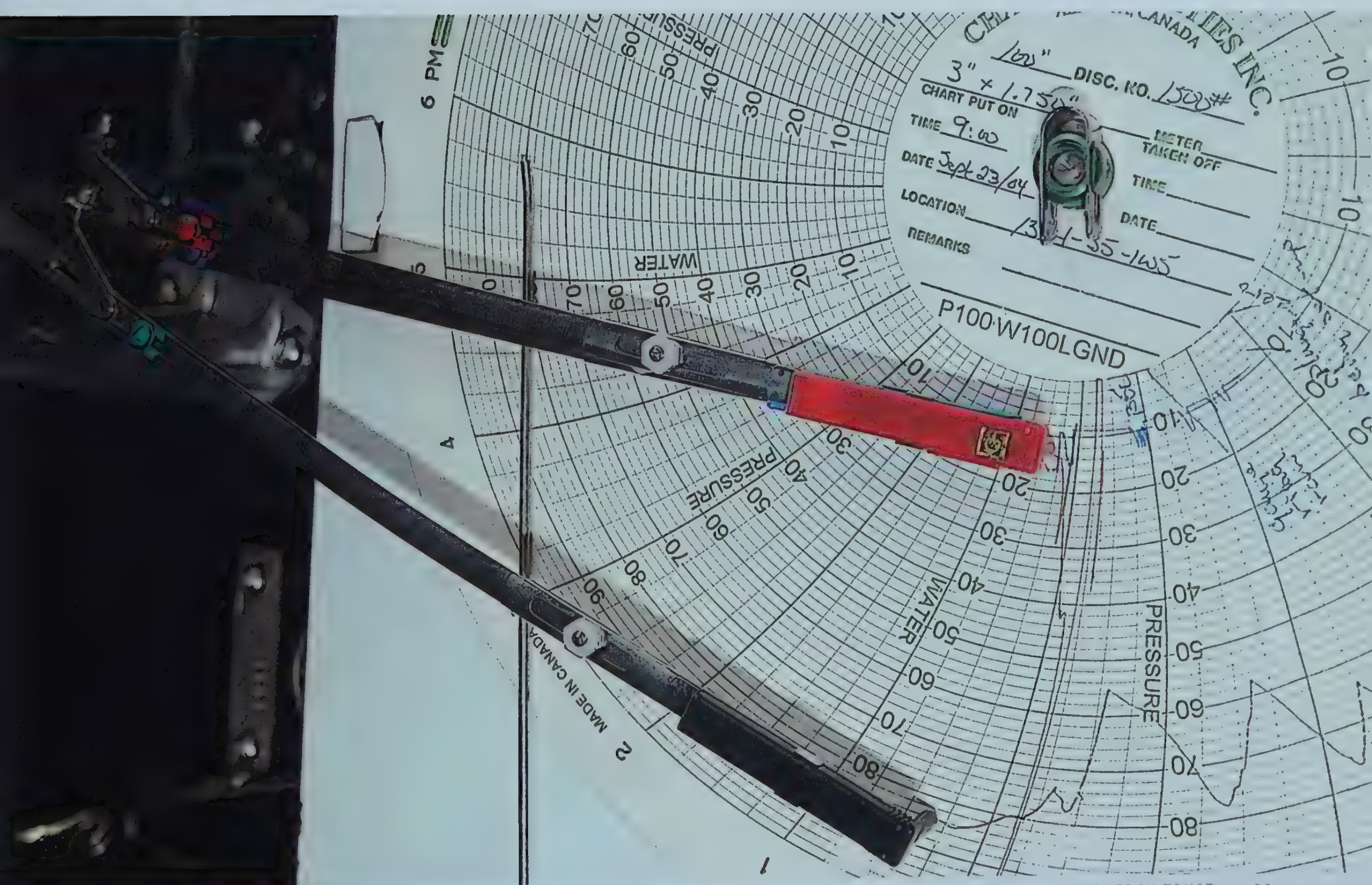
On November 20, 2003, the Trust announced the adoption of a Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan (the "DRIP"), effective for monthly distributions payable on and following December 15, 2003. The DRIP allows eligible unitholders to reinvest their proceeds in additional Trust units at a price equal to 95% of the volume-weighted average price during the predetermined pricing period, or receive a cash payment equal to 102% of the regular distribution.

Proceeds generated by the DRIP are utilized to partially fund the capital program. During 2004, $39.7 million of funding was contributed as a result of participation in the DRIP, under which 3.5 million units were issued.

Distributions have two components for taxation purposes: the taxable portion, which is considered income; and the return of capital, which reduces the unitholder's adjusted cost base ("ACB") each time a distribution is paid. A summary is sent to unitholders on an annual basis specifying what portion is taxable and what portion is a return of capital and is also available on APF's website. During 2004, distributions paid to Canadian residents were 68.3% taxable and 31.7% return of capital.

Distributions paid by the Trust to non-corporate unitholders who are U.S. residents or citizens are to be treated as "Qualified Dividends" under the Jobs and Growth Tax Relief Reconciliation Act of 2003 and are generally eligible for the reduced U.S. dividend tax rate. Distributions paid to U.S. residents during 2004 were 72.6% taxable and 27.4% return of capital.

Effective January 1, 2005, the Canadian government has applied a 15% withholding tax to all distributions paid to non-resident investors.



CORPORATE GOVERNANCE

The unitholders' interests are paramount in the operation and management of APF. The Trust is committed to maintaining the highest level of investor confidence through the development of its corporate governance policies. APF's Board of Directors is comprised of five independent members and two officers of the company who meet regularly to discuss matters of strategy and execution of the business plan. The Board also meets independently of management. APF's governance structure meets the guidelines established by the Toronto Stock Exchange ("TSX") and is reviewed and updated to reflect the ever changing business environment.

All Directors are elected by the unitholders of the Trust at the Annual Meeting. APF's Board members bring with them diverse skills and provide a depth of knowledge relating to the operations of the business. During 2004, as a result of the growth experienced through the Great Northern acquisition, APF added an independent director to the Board.

The Board works closely with senior management to provide guidance in executing the full cycle business plan that APF has set forth. Trust, integrity and responsibility define the relationship that exists between APF and its Board. The Board provides specific guidance with respect to material acquisitions and divestitures. The capital budget is reviewed and approved on an annual basis or as may be further required under special circumstances. The Board reviews and approves banking credit arrangements as well as reviewing quarterly unaudited financial statements and approving monthly the cash distribution.

The Board adheres to a Code of Ethics with emphasis on operational practices, independence and capital markets participation. Directors are subject to trading blackouts surrounding fiscal reporting periods and during times when the Trust may be reviewing or negotiating opportunities which could reasonably be expected to have an impact on the unit price. A blackout of trading in APF units takes place effective the fifteenth day of the month (or the next business day) following each quarterly reporting period and is lifted two business days after the release of the quarterly results to the market. In addition, other blackout periods may be imposed at various times throughout the year.

Committees

The Board of Directors is comprised of several committees which oversee specific aspects of APF's reporting and operations. The Board of Directors has an Audit and Reserves Committee, a Compensation Committee and a Nominating Committee.

AUDIT AND RESERVES COMMITTEE

The Audit and Reserves Committee is comprised of the five independent directors and assists the Board in fulfilling its oversight responsibilities with respect to the integrity and completeness of the annual and quarterly financial statements provided to unitholders and regulatory bodies; compliance with accounting and finance based legal and regulatory requirements; ensuring the independence of the external auditor, accounting systems and procedures and recommending for Board of Director approval the audited financial statements and other mandatory releases containing financial information. The committee also assists the Board in fulfilling its obligation to review the qualifications, experience, reserve audit approach and costs of the independent engineering firm that performs APF's reserve evaluation and to review the report annually.

COMPENSATION COMMITTEE

The Compensation Committee is comprised of three independent Directors. The committee is responsible to the Board for overseeing the development of competitive compensation policies designed to attract, develop and retain employees of the highest standard at all levels. It is responsible for recommending to the Board the compensation arrangements for senior officers and oversees the administration of succession planning. The committee reviews Directors' compensation and makes recommendations as deemed necessary. The compensation committee reviews independent third party reports to ensure compensation is competitive within the sector.

NOMINATING COMMITTEE

The Nominating Committee is tasked with ensuring APF's Board is comprised of individuals whose experience enables them to properly evaluate and guide the Trust's strategy. The committee is responsible for recruiting and recommending new members to fill Board vacancies giving consideration to competencies, skill sets and personal qualities of each candidate.

ENVIRONMENT, HEALTH & SAFETY

APF is committed to protecting the health and safety of all individuals affected by our activities. Our Environment, Health and Safety ("EH&S") group consists of three full time employees responsible for the execution of our policies, standards and procedures, ensuring that APF safeguards the environment and contributes to the well-being of the communities in which we live and operate.

Environment

Wherever APF operates, we conduct business with respect and care for the environment and systematically manage risks to drive sustainable business growth. This commitment is demonstrated by setting objectives to actively foster continual improvement. Environmental accomplishments for 2004 included:

- Continuation of the auditing program to ensure that environmental liabilities are identified and corrected. An environmental inventory management system was established, allocating funds on an annual basis, to actively manage any potential for liabilities.
- Establishment of a sound measurement system and completion of a green house emissions inventory based on previous year's data. This provides a benchmark for comparison as APF develops a comprehensive program for cost-effective management of greenhouse gases. The program encompasses energy conservation initiatives relating to water management and climate change.
- Further commitment to the Stewardship program initiated by the Canadian Association of Petroleum Producers by achieving the Silver Champion Level Reporter status. Participation in this program demonstrates a commitment to industry and corporate excellence in environmental, health, safety and socio-economic performance and will facilitate communication to all stakeholders.

APF has a fully integrated program to minimize the potential for incidents of all types which may result in damage to our facilities and/or injuries to our people and contractors. Safe practices are incorporated into ongoing operations through incident investigations, hazard and operability reviews, facility audits and near miss reporting. Health and Safety milestones for 2004 included:

- Strengthening the company-wide culture of safety by focusing on EH&S management systems and targeted safety-improvement efforts. APF established measurable performance targets relating to the health and safety of employees and contractors. Regular meetings and training programs are conducted to review and discuss health and safety regulations and workplace practices and procedures so that all employees and contractors have the skills necessary to attain these goals.
- Continued assessment of emergency response plans and procedures to ensure APF can react effectively and efficiently to incidents, thus minimizing any possible impact. Simulation events are conducted on a regular basis so emergency response plans remain current and appropriate.
- Continued third party and self-audits of APF operations are conducted on a regular basis to identify risks and initiate proactive steps to reduce or prevent exposure.

Excellence is achieved through the support and active participation of all management, employees and contractors working for APF. Our policy is reviewed annually and modified as appropriate.

CORPORATE SOCIAL RESPONSIBILITY

APF Energy actively seeks out opportunities to make a positive difference in the areas in which it operates. The Trust recognizes that stakeholders and communities that do well directly impact the success of APF. Employees are encouraged to become involved in their communities, fostering participation both at an individual and corporate level.

Community

During 2004, APF actively supported the Alberta Cancer Foundation, Jubilee Auditoria Foundation, Boys and Girls Club of Calgary, Inn From the Cold and the United Way of Calgary. In addition, for the second year running APF provided stockings filled with toys, books and learning supplies to children in need through its "Holiday Socks" program.

APF is also active with local organizations and events in several rural communities. These groups include: Friends of STARS (air ambulance), Radway 4H Beef Club, Estevan Shrine Circus and the 2004 Saskatchewan Summer Games.

APF pursues initiatives that support education and quality of life for youth and provide opportunities to the community at large.

Employees

APF provides its employees with the facilities and opportunities to better manage their work-life balance and enable continuing education. On-site fitness facilities are provided at no cost to the individual in support of a healthy lifestyle. APF values the contribution of each employee.

Investors

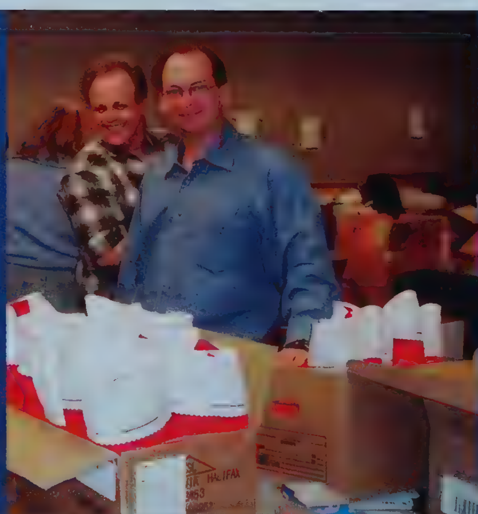
APF manages its oil and gas assets in a manner that balances the interests of the community with the economic value of the Trust's investments and the ultimate return to our unitholders. Through ongoing corporate reporting, unitholders have continuous access to disclosure of the Trust's performance and goals, making it easier to fully evaluate the Trust.

left to right: Steve Cloutier and Diana Segboer

< During 2004, APF and friends raised over $42,000 in support of Inn From the Cold.

APF partnered with Harvest Energy Trust to bring stockings filled with books, toys and school supplies to over 500 children in need in 2004 through the "Holiday Socks" program >

left to right: Brent McGhee and John Kierle



This Management's Discussion and Analysis ("MD&A") for APF Energy Trust ("APF" or the "Trust") should be read in conjunction with the December 31, 2004 and 2003 audited annual consolidated financial statements ("consolidated financial statements") and related note disclosures. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") and are presented in Canadian currency (except where indicated as being in another currency). APF is an oil and gas issuer and disclosures pertaining to oil and gas activities are presented in accordance with National Instrument 51-101 ("NI 51-101"). Additional information relating to APF, including disclosures required under NI 51-101, can be found in APF's Annual Information Form ("AIF") on SEDAR at www.sedar.com or on APF's website at www.apfenergy.com. This MD&A is dated March 1, 2005.

RESULTS OF OPERATIONS

PRODUCTION AND MARKETING

The Trust increased average production volumes by 28 percent to 16,012 boe/d for the year ended December 31, 2004, due primarily to the acquisition of Great Northern Exploration Ltd. ("Great Northern"), which added 5,600 boe/d of production effective June 2004, combined with a successful drilling program. The Great Northern acquisition and the Trust's gas-focused drilling program has shifted production from 45 percent natural gas-weighted in 2003, to 52 percent in 2004.

The Trust increased light/medium and heavy oil production by seven and nine percent respectively during 2004, despite unseasonable conditions during the third quarter that impacted the entire sector beyond the traditional spring break-up period. NGL and natural gas daily production volumes increased 112 and 47 percent respectively relative to the prior year, due primarily to the gas-levered Great Northern acquisition. The increase in production volumes is more pronounced in the fourth quarter and is more representative of the impact of Great Northern going forward.

	Three months ended December 31			Twelve months ended December 31		
	2004	2003	% Change	2004	2003	% Change
Light/medium crude oil (bbl/d)	6,443	5,205	24	5,802	5,399	7
Heavy oil (bbl/d)	1,291	1,293	–	1,167	1,073	9
NGL (bbl/d)	1,048	474	121	758	358	112
Natural gas (mcf/d)	58,008	36,929	57	49,712	33,799	47
Total (boe/d)	18,450	13,127	41	16,012	12,463	28
Production split						
Oil & NGLs	48%	53%	(10)	48%	55%	(12)
Natural gas	52%	47%	12	52%	45%	14

Crude oil is sold under 30-day evergreen contracts while the majority of natural gas production is sold in the spot market. Approximately 15 percent of natural gas volumes are sold to aggregators pursuant to long-term contracts declining from 20 percent prior to acquiring the Great Northern volumes.

REALIZED OIL AND GAS PRICES

The Trust's combined crude oil pricing before derivatives increased 24 percent for the year and 42 percent for the three months ended December 31, 2004, relative to the industry benchmark West Texas Intermediate ("WTI") measured in U.S. currency, which increased 33 and 55 percent over the same periods. The difference is consistent with observed differentials between WTI and the Canadian dollar-denominated Edmonton Par crude, which increased 22 and 46 percent for the year and three months ended December 31, 2004 respectively. U.S. and Canadian product differentials are primarily driven by U.S./Cdn. currency exchange rates; however, quality differentials and U.S. demand for Canadian imports also impact relative pricing. The remaining difference between the Trust's combined crude pricing before derivatives as compared to Edmonton Par is due to product quality differentials attributable to the Trust's heavy oil production. For the year ended December 31, 2004, heavy oil as a percentage of total crude oil production remained relatively unchanged whereas this percentage for the three months ended December 31, 2004 decreased from 20 percent to 17 percent. As a result, the Trust realized a higher average price relative to the comparative period.

Natural gas pricing before derivatives for the year ended December 31, 2004 increased two percent over the prior year. This is consistent with the one percent increase in the benchmark AECO price for the corresponding period as the relative balance between the supply of and demand for natural gas in North America remained constant. For the three months ended December 31, 2004, the 21 percent increase in the price of natural gas relative to the comparable quarter is due mainly to depressed North American natural gas prices during October and November 2003.

Price realizations include the impact of realized crude oil and natural gas financial derivative instruments. For the year ended December 31, 2004, crude oil price realizations increased 11 percent to $38.19 per bbl and include the settlement of crude oil derivatives, which lowered pricing before derivatives by 14 percent or $6.44 per bbl. Crude oil price realizations during the fourth quarter of 2004 were 18 percent higher than 2003 price realizations despite derivative losses that lowered per barrel pricing 20 percent from $46.43 before derivatives to $37.23 after realized derivatives.

The impact of realized derivatives did not significantly impact natural gas price realizations. Consistent with pricing before derivatives, for the year ended December 31, 2004, price realizations were up slightly to $6.80 per mcf, which represents a two percent increase over the prior year. Price realizations during the fourth quarter of 2004 were up 18 percent as compared to 2003, due to depressed North American natural gas prices during the first two months of the fourth quarter of 2003.

Effective January 1, 2004, the Trust began segregating costs associated with the transportation and selling of crude oil, natural gas and NGLs. Previously, the Trust had followed industry practice, presenting revenue net of these costs. The comparative figures have been restated with these costs segregated, resulting in an increase to the gross price per mcf (boe).

	Three months ended December 31			Twelve months ended December 31		
Prices – Before Derivatives ($Cdn.)	2004	2003	% Change	2004	2003	% Change
		Restated			Restated	
Light/medium crude oil (bbl)	$ 49.89	$ 35.21	42	$ 47.29	$ 38.03	24
Heavy oil (bbl)	29.15	22.48	30	31.43	26.19	20
Total crude oil (bbl)	46.43	32.68	42	44.63	36.07	24
NGLs (bbl)	41.82	31.37	33	40.09	31.83	26
Natural gas (mcf)	6.74	5.59	21	6.79	6.64	2
Total (boe)	$ 43.01	$ 33.04	30	$ 42.40	$ 37.66	13
Realized Oil and Gas Derivatives ($Cdn.)						
Crude oil (bbl)	$ (9.20)	$ (1.01)	811	$ (6.44)	$ (1.61)	300
Natural gas (mcf)	0.05	0.16	(69)	0.01	0.02	(50)
Total (boe)	$ (3.69)	$ (0.04)	9,125	$ (2.78)	$ (0.79)	252
Prices – After Realized Oil and Gas Derivatives ($Cdn.)						
Total crude oil (bbl)	$ 37.23	$ 31.67	18	$ 38.19	$ 34.46	11
NGLs (bbl)	41.82	31.37	33	40.09	31.83	26
Natural gas (mcf)	6.79	5.75	18	6.80	6.66	2
Total (boe)	$ 39.32	$ 33.00	19	$ 39.62	$ 36.87	7
Reference Pricing						
WTI ($U.S./bbl)	$ 48.28	$ 31.18	55	$ 41.40	$ 31.04	33
Edmonton Par ($Cdn./bbl)	$ 57.71	$ 39.56	46	$ 52.55	$ 43.14	22
AECO gas ($Cdn./mcf)	$ 7.08	$ 5.59	27	$ 6.79	$ 6.70	1
Foreign exchange ($U.S./$Cdn.)	1.2207	1.3157	(7)	1.3282	1.4010	(5)

The Trust uses derivative instruments to manage commodity price fluctuations and stabilize cash flows available for unitholder distributions and future development programs (see Risk Management section of this document). Derivative instruments are also used to help manage exposures to foreign currency exchange rates, interest rates and electricity rates. APF does not enter into derivative contracts for speculative purposes. A detailed summary of the Trust's derivative position at December 31, 2004 is presented in the Risk Management section of this document.

APF's current approach to derivatives involves the use of swaps, collars and sold WTI call options for light and medium crude oil and swaps and collars for natural gas. The following table summarizes crude oil and natural gas derivative contracts settled during 2004 as a percentage of quarterly production volumes and contracts outstanding as at the date of this report relating to future production:

	2004				2005				2006	
Percentage of production hedged	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
Crude oil	49%	44%	44%	49%	34%	50%	47%	27%	27%	7%
Natural gas	33%	30%	35%	22%	16%	41%	41%	25%	16%	0%

OIL AND GAS REVENUE

Gross oil and gas revenue for the year ended December 31, 2004, increased 45 percent over the prior year, due to the Trust's acquisition of Great Northern and sustained strength in commodity prices. Seven months of Great Northern production volumes are reflected in the 2004 fiscal year. The impact of Great Northern is more evident when comparing the three month periods ended December 31. Gross oil and gas revenue for the fourth quarter of 2004 increased 83 percent over the comparable period in 2003. The variance can be explained by a 30 percent increase in prices (before realized derivatives) on 41 percent higher production volumes.

Effective January 1, 2004, the Trust began segregating costs associated with the transportation and selling of crude oil, natural gas and NGLs. Previously, the Trust followed industry practice, presenting revenue net of these costs. The comparative figures have been restated with these costs segregated, resulting in an increase to the gross price per mcf (boe).

Oil and Gas	Three months ended December 31			Twelve months ended December 31		
($000 except per boe amounts)	2004	2003	% Change	2004	2003	% Change
		Restated			Restated	
Light/medium crude oil sales	29,571	16,862	75	100,419	74,934	34
Heavy oil sales	3,463	2,675	29	13,423	10,260	31
NGL sales	4,031	1,368	195	11,115	4,157	167
Natural gas sales	35,944	18,997	89	123,527	81,938	51
Gross oil and gas revenue	73,009	39,902	83	248,484	171,289	45
Realized oil and gas derivatives	(6,260)	(44)	14,127	(16,305)	(3,565)	357
Transportation	(1,427)	(1,150)	24	(5,245)	(4,174)	26
Other	1,962	421	366	4,729	1,925	146
Net oil and gas revenue	67,284	39,129	73	231,663	165,475	40
Per boe	$ 39.64	$ 32.39	22	$ 39.53	$ 36.38	9

ROYALTIES

Royalties paid are calculated in accordance with royalty reference rates directly related to gross oil and gas revenues generated by the Trust from mineral leases with the Crown, freeholders and other operators. Total royalties for the year ended December 31, 2004, as a percentage of gross oil and gas revenue were consistent with rates paid during the prior year. Total royalties recorded for the fourth quarter of 2004 are approximately 18 percent of gross oil and gas revenue due to an adjustment for royalties previously accrued for during 2004. Going forward, the Trust expects royalty rates to remain consistent with annual rates recorded in 2004 and 2003.

	Three months ended December 31			Twelve months ended December 31		
($000 except per boe amounts)	2004	2003	% Change	2004	2003	% Change
		Restated			Restated	
Crown royalties	8,711	4,838	80	30,429	19,364	57
Freehold royalties	3,231	2,120	52	12,679	10,193	24
Overriding royalties	1,309	609	115	4,602	2,916	58
Total royalties	13,251	7,567	75	47,710	32,473	47
% of gross oil and gas revenue	18.1%	19.0%	(4)	19.2%	19.0%	1
Per boe	$ 7.81	$ 6.27	25	$ 8.14	$ 7.14	14

OPERATING EXPENSE

On a gross and per boe basis, operating costs were higher for the three months and year ended December 31, 2004 when compared to the same periods in 2003 due primarily to the acquisition and integration of Great Northern. The Trust completed a significant number of optimization projects planned for Great Northern properties during the third and fourth quarters of 2004 and operating costs have trended lower following completion of these initiatives. The Trust has planned for additional initiatives to control future field costs and expects operating costs to average $9.00 per boe during fiscal 2005.

	Three months ended December 31			Twelve months ended December 31		
($000 except per boe amounts)	2004	2003	% Change	2004	2003	% Change
		Restated			Restated	
Operating expense	15,628	9,619	62	51,788	32,370	60
Per boe	$ 9.21	$ 7.96	16	$ 8.84	$ 7.12	24

PRODUCT NETBACKS

Light/medium crude oil netbacks for the year ended December 31, 2004 decreased by two percent from $19.76 to $19.31, due primarily to lower price realizations after derivatives and higher operating costs related to Great Northern properties. The 2004 quarterly light/medium netback increased four percent over the prior period presented, resulting from higher prices received before derivatives and a smaller increase in operating costs relative to the prior period.

Light/medium crude oil	Three Months Ended December 31			Twelve Months Ended December 31		
($Cdn. per bbl)	2004	2003	% Change	2004	2003	% Change
		Restated			Restated	
Price – After realized derivatives	$ 38.85	$ 33.95	14	$ 39.55	$ 36.10	10
Royalties	(9.24)	(7.55)	22	(9.01)	(7.56)	19
Operating expense	(12.76)	(10.26)	24	(11.23)	(8.78)	28
Operating netback	$ 16.85	$ 16.14	4	$ 19.31	$ 19.76	(2)

Heavy oil netbacks increased 22 percent and 95 percent for the year and three months ended December 31, 2004, respectively, as compared to the prior periods in 2003. The increase is due primarily to higher price realizations offset by an increase in royalty expense. Operating costs for the year ended December 31, 2004, increased four percent over the prior year but were down 14 percent during the fourth quarter due to additional processing recoveries that reduce operating costs.

	Three months ended December 31			Twelve months ended December 31		
Heavy oil ($Cdn. per bbl)	2004	2003	% Change	2004	2003	% Change
		Restated			Restated	
Price – after realized derivatives	$ 29.15	$ 22.48	30	$ 31.43	$ 26.19	20
Royalties	(4.68)	(3.51)	33	(4.42)	(2.56)	73
Operating expense	(9.93)	(11.53)	(14)	(11.09)	(10.62)	4
Operating netback	$ 14.54	$ 7.44	95	$ 15.92	$ 13.01	22

NGL netbacks increased 33 percent and 59 percent for the year and three months ended December 31, 2004, respectively, relative to the corresponding periods in 2003 due to higher price realizations in a strong commodity price environment.

	Three months ended December 31			Twelve months ended December 31		
NGLs ($Cdn. per bbl)	2004	2003	% Change	2004	2003	% Change
		Restated			Restated	
Price – after realized derivatives	$ 41.82	$ 31.37	33	$ 40.09	$ 31.83	26
Royalties	(7.52)	(9.84)	(24)	(10.31)	(9.41)	10
Operating expense	–	–	–	–	–	–
Operating netback	$ 34.30	$ 21.53	59	$ 29.78	$ 22.42	33

Natural gas netbacks declined six percent for the year ended and increased 15 percent for the three months ended December 31, 2004. Price realizations for the year ended December 31, 2004 were relatively flat as compared to 2003 and the 21 percent quarter-over-quarter increase in the price of natural gas after deducting transportation is due to unusually low North American natural gas prices experienced during October and November of 2003. The increase in operating costs per mcf is due to the execution of planned optimization initiatives related to Great Northern properties.

	Three months ended December 31			Twelve months ended December 31		
Natural gas ($Cdn. per mcf)	2004	2003	% Change	2004	2003	% Change
		Restated			Restated	
Price – after realized derivatives	$ 6.79	$ 5.75	18	$ 6.80	$ 6.66	2
Transportation	(0.27)	(0.34)	(21)	(0.29)	(0.34)	(15)
	6.52	5.41	21	6.51	6.32	3
Royalties	(1.22)	(0.92)	33	(1.31)	(1.24)	6
Operating expense	(1.29)	(0.99)	30	(1.28)	(0.89)	44
Operating netback	$ 4.01	$ 3.50	15	$ 3.92	$ 4.19	(6)

On a combined boe basis, the increase in price realizations less transportation and other income is consistent with higher commodity prices offset by realized derivative losses. Despite the negative impact of derivatives and higher operating costs during the year ended December 31, 2004, netbacks increased two percent over 2003. Netbacks for the fourth quarter performed better against the comparable quarter due to a weaker commodity price environment during the fourth quarter of 2003, combined with operating costs that have trended lower since the third quarter of 2004.

	Three months ended December 31			Twelve months ended December 31		
Combined ($Cdn. per boe)	2004	2003	% Change	2004	2003	% Change
		Restated			Restated	
Price – After realized derivatives	$ 39.32	$ 33.00	19	$ 39.62	$ 36.87	7
Transportation	(0.84)	(0.95)	(12)	(0.90)	(0.92)	(2)
Other	1.18	0.35	237	0.82	0.41	100
	39.66	32.40	22	39.54	36.36	9
Royalties	(7.81)	(6.27)	25	(8.14)	(7.14)	14
Operating expense	(9.21)	(7.97)	16	(8.84)	(7.12)	24
Operating netback	$ 22.64	$ 18.16	25	$ 22.56	$ 22.10	2

GENERAL AND ADMINISTRATIVE

General and administrative ("G&A") expense for the year ended December 31, 2004, increased commensurate with the increased staffing levels required by growth in the Trust's operations from recent corporate and property acquisitions. On a per boe basis, G&A has declined 18 percent for the year and 43 percent for the three months ended December 31, 2004, due primarily to lower costs accrued for under the Trust's short-term incentive plan ("STIP").

	Three months ended December 31			Twelve months ended December 31		
($000 except per boe amounts)	2004	2003	% Change	2004	2003	% Change
		Restated			Restated	
General and administrative	3,197	3,980	(20)	10,635	10,023	6
Per boe	$ 1.88	$ 3.29	(43)	$ 1.81	$ 2.20	(18)

The STIP is designed to align employee and unitholder interests and to reward exceptional employee performance. The STIP enables all eligible employees to participate in a group bonus pool, provided the Trust generates a minimum total annual return of 10 percent. The total annual return on the Trust units as calculated by management for the year ended December 31, 2004, was 10.7 percent (2003 – 50.0 percent). Based on this total return figure, the 2004 STIP bonus pool was $1.17 million (2003 – $3.35 million). Senior employees, including officers, are also eligible to receive performance bonuses based on criteria applicable to their individual responsibilities. Excluding the STIP, G&A cost per boe for the year and three months ended December 31, 2004, was $1.62 (2003 – $1.47).

INTEREST ON LONG-TERM DEBT AND CONVERTIBLE DEBENTURES

Interest expense on long-term debt on a per boe basis remained consistent with 2003 for both the year and three months ended December 31, 2004. On a gross basis, interest expense has increased commensurate with higher average debt levels used to fund growth in the Trust's operations.

Interest and financing charges on convertible debentures for the year ended December 31, 2004, increased 97 percent in dollar terms and 53 percent on a per boe basis due to the fact that the debentures were issued on July 3, 2003, resulting in only six months of interest expense being included in the comparative figure. For the quarter ended December 31, 2004, interest expense on debentures decreased one percent in dollar terms as compared to the same period in 2003 due to $0.22 million in conversions during 2004.

Effective December 31, 2004, the Trust retroactively adopted the revised CICA Handbook Section 3860 ("HB 3860"), "Financial Instruments - Presentation and Disclosure" for financial instruments that may be settled at the issuer's option in cash or its own equity instruments. The revised standard requires the Trust to classify the convertible debenture proceeds as either debt or equity based on fair value measurement and the substance of the contractual arrangement. The Trust previously presented the convertible debenture proceeds (net of financing costs) and related interest obligations as equity on the consolidated balance sheet on the basis that the Trust could settle its obligations in exchange for Trust units. The comparative figures presented have been restated to conform to the amended accounting standard.

	Three months ended December 31			Twelve months ended December 31		
($000 except per boe amounts)	2004	2003	% Change	2004	2003	% Change
		Restated			Restated	
Interest on long-term debt	1,556	1,088	43	5,405	4,171	30
Per boe	$ 0.92	$ 0.90	2	$ 0.92	$ 0.92	1
Interest and financing charges on convertible debentures	1,327	1,347	(1)	5,263	2,669	97
Per boe	$ 0.78	$ 1.12	(30)	$ 0.90	$ 0.59	53

DEPLETION, DEPRECIATION, AND ACCRETION

Depletion, depreciation and accretion ("DD&A") per boe increased 25 percent for the year and decreased 35 percent for the quarter ended December 31, 2004, respectively, as compared to the prior periods presented. The annual increase is due primarily to the acquisition of Great Northern resulting in a larger depletable base. The decrease quarter-over-quarter is attributable to an increase in proved reserves following the Trust's most active drilling quarter and revisions to the Trust's depletable base during the fourth quarter of 2004.

Effective January 1, 2004, the Trust retroactively adopted CICA Handbook Section 3110, "Asset Retirement Obligations" (ARO). The new standard requires that the fair value of an asset retirement obligation be recognized in the period in which it is incurred with a corresponding increase to property, plant and equipment. Prior periods presented include the impact of adopting this standard.

	Three months ended December 31			Twelve months ended December 31		
($000 except per boe amounts)	2004	2003	% Change	2004	2003	% Change
		Restated			Restated	
Depletion, depreciation and accretion	16,108	17,704	(9)	85,997	53,389	61
Per boe	$ 9.49	$ 14.66	(35)	$ 14.68	$ 11.74	25

UNIT-BASED COMPENSATION

For the year and three months ended December 31, 2004, the Trust recorded a recovery of unit-based compensation of $0.88 million and $1.87 million respectively, as compared to an expense of $1.24 million and $0.58 million for the corresponding periods in 2003. The decrease in unit-based compensation expense recorded in 2004 is due to a change in the Trust's approach to valuing equity instruments awarded to employees and directors. During the fourth quarter of 2004, the Trust began using the Black-Scholes option-pricing model to estimate the fair value of unit-based compensation. Previously, the Trust used the excess of the period-end market price over the exercise price as an estimate of fair value.

Effective December 31, 2003, the Trust prospectively adopted CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments." The standard requires that equity instruments awarded to employees after December 31, 2002, be measured at fair value and recognized over the vesting period. Companies that adopted the standard during 2003 were permitted to provide proforma disclosure of equity instruments granted before January 1, 2003. Comparative figures for 2003 have been restated to reflect the impact of unit-based compensation.

	Three months ended December 31			Twelve months ended December 31		
($000 except per boe amounts)	2004	2003	% Change	2004	2003	% Change
		Restated			Restated	
Compensation expense (recovery)	(1,866)	582	(421)	(877)	1,241	(171)
Per boe	$ (1.10)	$ 0.48	(328)	$ (0.15)	$ 0.27	(155)

TAXES

Saskatchewan capital tax and federal large corporation tax increased 22 percent for the year and 54 percent for the quarter ended December 31, 2004 as compared to fiscal 2003, reflecting an increase in taxable capital after the acquisition of Great Northern.

Future income taxes are recorded on corporate acquisitions to the extent the book value of assets acquired, excluding goodwill, exceeds the tax basis. This future income tax liability increases the book cost of the assets acquired. It is anticipated that the future income tax liability will not be paid by APF Energy but will instead be passed on to unitholders along with the income. Accordingly, this income tax liability will reduce each year and will be recognized as an income tax recovery at that time, to the extent that no income taxes were paid by APF Energy. For the year ended December 31, 2004, the Trust recovered $27.02 million in future income taxes compared to a future tax recovery of $14.21 million in 2003. At December 31, 2004 the Trust had a future income tax liability of $86.71 million as compared to $63.99 million at the end of 2003. The increase is due primarily to the future tax liability acquired with Great Northern, less recoveries recognized during the year. The December 31, 2003 comparative figures include the impact of adopting CICA Handbook Section 3110 "Asset Retirement Obligations".

	Three months ended December 31			Twelve months ended December 31		
($000 except per boe amounts)	2004	2003	% Change	2004	2003	% Change
		Restated			Restated	
Capital and other taxes	957	623	54	3,321	2,720	22
Per boe	$ 0.56	$ 0.52	9	$ 0.57	$ 0.60	(5)
Recovery of future taxes	(5,712)	451	1,367	(27,016)	(14,207)	90

SUMMARY OF ANNUAL RESULTS

	Year Ended December 31		
($000, except per unit amounts)	2004	2003	2002
		Restated	Restated
Total revenue	184,152	132,984	75,314
Net income	49,636	40,608	11,582
Per unit – basic	$ 1.02	$ 1.31	$ 0.57
Per unit – diluted	$ 1.02	$ 1.29	$ 0.56
Cash flow from operations	107,126	81,019	43,789
Per unit	$ 2.21	$ 2.62	$ 2.14
Distributions	96,930	68,713	37,766
Per unit	$ 2.00	$ 2.20	$ 1.81
Total assets	862,170	498,750	306,322
Total long-term debt	169,000	98,000	88,000

Total revenue is primarily affected by commodity prices, production volumes, royalties and realized and unrealized (non-cash) derivative gains and losses. Total revenue has increased commensurate with strong commodity prices, corporate and property acquisitions and internal development activity. The Trust has been an active acquirer over the past three years, completing the acquisition of Great Northern during 2004; the acquisitions of CanScot Resources, Nycan Energy, Hawk Oil and an additional interest at Swan Hills during 2003; and the acquisitions of Kinwest Resources and Paddle River assets in 2002.

The new accounting requirement to recognize gains/losses in the Trust's unrealized derivative position has introduced additional non-cash volatility in reported income. Prior to fiscal 2004, derivative gains/losses were reflected in income upon settlement of the related contracts; the 2003 and 2002 figures presented above have not been restated in accordance with the transitional provision of the new accounting pronouncement.

Net income has increased each year; however, the growth in income was lowered by realized oil and gas derivative losses, higher royalty expense in proportion with gross oil and gas revenues and higher operating costs and DD&A as a percentage of gross oil and gas revenues. The sustained strength in commodity prices, particularly light/medium crude oil, has resulted in larger than expected derivative losses. Operating costs associated with newly-acquired Great Northern properties escalated through the third quarter of 2004, but have trended downward during the fourth quarter and should remain stable throughout fiscal 2005. As the Trust is able to take advantage of internal development opportunities, DD&A per boe is expected to remain consistent with 2004.

Given the sustained strength in commodity prices during 2004, despite realized oil and gas derivative losses and higher cash operating costs, the Trust has generated growth in cash flow from operations. Cash distributions have also increased; however, distributions declared per unit have decreased to provide the Trust with additional development capital to sustain future cash distributions. Non-cash items, such as depletion, depreciation and accretion, future income taxes, and unrealized gains or losses on derivative instruments, do not influence the Trust's ability to distribute cash to unitholders.

The increase in total assets year-over-year is due primarily to oil and gas assets and goodwill purchased through corporate acquisitions. The increase in total long-term debt is commensurate with a larger asset base and increased development expenditures.

SUMMARY OF QUARTERLY RESULTS

The following table highlights the Trust's performance for the two most recent fiscal years presented on a quarterly basis:

	2004 Restated				2003 Restated			
($000, except per unit amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Total revenue	66,066	46,776	39,169	32,141	31,543	32,737	33,295	35,410
Net income	34,870	3,176	4,788	6,802	(3,852)	9,799	20,977	13,687
Per unit – basic	$ 0.60	$ 0.06	$ 0.11	$ 0.18	$ (0.11)	$ 0.30	$ 0.65	$ 0.54
Per unit – diluted	$ 0.58	$ 0.06	$ 0.11	$ 0.18	$ (0.11)	$ 0.30	$ 0.65	$ 0.54
Cash flow from operations	31,125	29,729	24,415	21,857	14,873	19,389	21,563	25,194
Per unit	$ 0.53	$ 0.54	$ 0.56	$ 0.58	$ 0.44	$ 0.60	$ 0.67	$ 1.00
Distributions	28,068	26,517	22,516	19,829	17,822	18,909	18,916	13,066
Per unit	$ 0.48	$ 0.48	$ 0.51	$ 0.53	$ 0.53	$ 0.57	$ 0.59	$ 0.51
Total assets	862,170	833,093	853,234	496,871	498,750	501,689	446,527	377,916
Total long-term debt	169,000	150,000	190,000	55,000	98,000	90,000	102,000	97,000

Total revenue has trended upward over the past eight quarters. The new accounting requirement to mark the Trust's unrealized derivative position to market at period end and record the change in income, lowered 2004 quarterly revenues by $3.27 million in Q1, $2.22 million in Q2, and $6.09 million in Q3, and increased Q4 total revenue by $0.22 million. As previously mentioned, unrealized gains/losses were not recorded for periods prior to 2004.

The volatility in quarterly net income over the past two years is partially due to derivative gains/losses, higher operating costs and non-cash charges such as DD&A as well as the timing of certain other cash expenses. Net income for the fourth quarter of 2003 is significantly lower than any other quarter reported over the past two years due to the STIP bonus accrual recorded at December 31.

Cash flow from operations and cash distributions to unitholders have increased steadily since the fourth quarter of 2003. Growth in cash flows has been less than the observed increase in gross oil and gas revenues due to realized derivative losses and higher cash operating costs. Non-cash items such as DD&A, future income taxes, and unrealized gains or losses on derivative instruments, do not influence the Trust's ability to distribute cash to unitholders.

Significant corporate and property acquisitions explain the movement in total assets and total long-term debt. Great Northern was acquired in June 2004; CanScot was acquired in September 2003; Nycan Energy in April 2003; and Hawk Oil was acquired in February 2003. The increase in long-term debt at the end of 2004 is the result of the most active capital development program in the Trust's history.

LIQUIDITY AND CAPITAL RESOURCES

Working Capital

At December 31, 2004, the Trust had a working capital deficit of approximately $11.99 million as compared to $8.19 million at December 31, 2003. The 46 percent increase is the result of the fourth quarter of 2004 being the Trust's most active drilling quarter since inception. The Trust anticipates cash flow from operations will be sufficient to meet this current deficit.

Included in the calculation of working capital are unrealized derivative instruments measured at fair value and recorded on the balance sheet as a current asset or liability in accordance with EIC 128. At December 31, 2004, a current derivative asset of $3.31 million was recorded on the balance sheet (2003 – $nil) offset by a current derivative liability of $3.14 million (2003 – $nil). The ultimate settlement of these derivative positions is dependent upon changes in commodity prices, foreign currency exchange rates, and interest rates during the remaining life of derivative contracts.

LONG-TERM DEBT

Credit facility

At December 31, 2004, the Trust had a revolving credit and term facility for $200 million (2003 – $150 million) with a syndicate of Canadian financial institutions. The facility may be drawn down or repaid at any time but there are no scheduled repayment terms.

The debt is collateralized by a $300 million demand debenture containing a first fixed charge on all crude oil and natural gas assets of APF as required by the lenders and a floating charge on all other property together with a general assignment of book debts. At December 31, 2004, the interest rate was Bank Prime of 4.25 percent plus 0.125 percent (2003 – 4.5 percent plus 0.125 percent).

Convertible debentures

On July 3, 2003, the Trust issued $50 million of 9.40 percent unsecured subordinated convertible debentures ("convertible debentures") for proceeds of $50 million ($47.68 million net of issue costs). Interest is paid semi-annually on January 31 and July 31 and the instruments mature on July 31, 2008.

The debentures are convertible at the holder's option into fully paid and non-assessable Trust units at any time prior to July 31, 2008, at a conversion price of $11.25 per Trust unit. The holder will receive accrued and unpaid interest up to and including the conversion date. The Trust can redeem the debentures after July 31, 2006, or earlier under certain circumstances. The convertible debentures become redeemable at $1,050 per convertible debenture, in whole or in part, after July 31, 2006 and redeemable at $1,025 after July 31, 2007 and before maturity. An additional 4.32 million Trust units (2003 – 2.18 million) were added to the weighted average number of units outstanding for the year relating to the assumed conversion of debentures.

The following table highlights accretion, conversions and the carrying value of Trust's convertible debentures:

($000)	Liability component	Equity component	Total
Issued on July 3, 2003	48,817	1,183	50,000
Accretion of liability during 2003	89	–	89
Conversions into Trust units during 2003	(1,187)	(29)	(1,216)
Carrying value at December 31, 2003	47,719	1,154	48,873
Accretion of liability during 2004	193	–	193
Conversions into Trust units during 2004	(215)	(5)	(220)
Carrying value at December 31, 2004	47,697	1,149	48,846

UNITHOLDERS' EQUITY

Trust unit offerings

At December 31, 2004, the Trust had 58.85 million Trust units outstanding (2003 – 34.07 million) and a market capitalization of approximately $690 million (2003 – $427 million). During 2004, the Trust completed three Trust Unit issuances:

Date of issue	Units issued	Price per unit	Gross proceeds	Use of proceeds
1. February 4, 2004	4.77 million	$11.60	$55.27	Reduced financial leverage; a portion of proceeds were used to finance Great Northern acquisition.
2. June 4, 2004	12.89 million	$12.18	$156.94	Issued as part of the Great Northern acquisition.
3. September 8, 2004	3.10 million	$11.30	$35.03	Reduced financial leverage and partially fund the Trust's expanded 2004 capital expenditure program.

As at February 28, 2005, APF had 59.56 million Trust units outstanding.

DISTRIBUTION REINVESTMENT PLAN

Commencing December, 2003, the Trust initiated a distribution reinvestment plan ("DRIP") for Canadian resident unitholders. The DRIP permits eligible unitholders to direct their distributions to the purchase of additional units at 95 percent of the average market price as defined in the plan ("Regular DRIP").

The premium distribution component permits eligible unitholders to elect to receive 102 percent of the cash the unitholder would otherwise have received on the distribution date ("Premium DRIP"). Participation in the Regular DRIP and Premium DRIP is subject to proration by the Trust. The DRIP also allows those unitholders who participate in either the distribution reinvestment component or the premium distribution component to purchase additional Trust units directly from the Trust for cash at a purchase price equal to the average market price (with no discount) in minimum amounts of $1,000 per remittance and up to $100,000 aggregate amount of remittances by a unitholder in any calendar month, all subject to an overall annual limit of two percent of the outstanding Trust units.

The Trust issued 3.03 million Trust units during the year ended December 31, 2004 (2003 - 0.12 million) pursuant to the Premium DRIP, generating $33.89 million in proceeds (2003 - $1.33 million). During the fourth quarter of 2004, the Trust issued 0.89 million Trust units (2003 - 0.12 million) for total proceeds of $9.91 million (2003 - $1.33 million) in respect of the Premium DRIP. Under the Regular DRIP, the Trust issued 0.52 million Trust units during 2004 (2003 - 0.02 million) for proceeds of $5.76 million (2003 - $0.27 million). During the quarter ended December 31, 2004, the Trust issued 0.16 million units (2003 - 0.02 million) for proceeds of $1.81 million (2003 - $0.27 million).

UNITHOLDER DISTRIBUTIONS

Distributions to unitholders are paid monthly and can fluctuate depending on the cash flow generated from operations. Distributable cash is dependent upon many factors including commodity prices, production levels, debt levels, capital spending requirements, and other market factors. The Trust declared unitholder distributions of $96.93 million, or $2.00 per Trust unit during the year ended December 31, 2004 (2003 – $68.71 million or $2.20 per unit). For the quarter ended December 31, 2004, the Trust declared distributions of $28.07 million, or $0.48 per Trust unit (2003 – $17.82 million or $0.53 per unit).

The Trust distributed 90 percent of cash flow from operations for both the three months and year ended December 31, 2004, as compared to 120 percent and 85 percent for the three months and the year ended December 31, 2003.

TAXATION OF UNITHOLDER DISTRIBUTIONS

Distributions to unitholders have two components for taxation purposes: the taxable return on capital portion and the tax deferred return of capital. The return on capital is considered taxable to unitholders whereas the return of capital reduces the adjusted cost base of the unit each time a distribution is received.

The following table summarizes the components of annual distributions paid by the Trust since inception:

HISTORICAL CANADIAN TAX INFORMATION

Payment period	Taxable amount per unit (other income)	Tax deferred amount per unit (return of capital)	Cash distribution per unit for tax purposes	Taxable percentage	Tax deferred percentage
2004	$1.483	$0.687	$2.170	68.345%	31.655%
2003	$1.718	$0.462	$2.180	78.814%	21.186%
2002	$1.143	$0.657	$1.800	63.517%	36.483%
2001	$1.741	$1.304	$3.045	57.175%	42.825%
2000	$1.181	$0.719	$1.900	62.137%	37.863%
1999	$0.526	$1.029	$1.555	33.826%	66.174%
1998	$0.453	$1.387	$1.840	24.625%	75.375%
1997	$0.597	$0.913	$1.510	39.536%	60.464%
Total	$8.842	$7.158	$16.00		

Distribution payments to U.S.-resident unitholders are subject to 15 percent Canadian withholding tax, which is deducted from the distribution amount prior to deposit into accounts.

CAPITAL EXPENDITURES

Net capital expenditures for the year ended December 31, 2004 totalled $369.71 million (2003 – $191.18 million). The current year includes the $291.08 million gross acquisition cost of Great Northern and the comparative year reflects the gross acquisition cost of Hawk Oil Inc. ($49.70 million), Nycan Energy Corp. ($42.44 million), and CanScot Resources Ltd. ($42.08 million). Overall, the aggregate value of these corporate acquisitions during 2004 exceeded 2003 levels by $156.86 million. The $24.13 million increase in seismic, drilling and completions and production facilities over 2003 is attributable to a larger asset base and development opportunities resulting from the aforementioned acquisitions completed in 2003 and 2004.

Given the magnitude of corporate acquisitions during 2004, fewer property acquisitions were completed as compared to 2003, when the Trust acquired incremental production at Countess for $7.03 million and an interest in Swan Hills Unit No. 1 for $15.9 million. Conversely, the Trust was more active at crown land sales during 2004, building an inventory of high-quality drilling prospects so that production and reserves can be added independent of acquisition activity.

Net capital expenditures for the quarter increased to $39.25 million from $8.59 million during the same period in 2003 and is explained by the fact that the three months ended December 31, 2004 was the Trust's most active quarter for drilling and development since inception, as the Trust capitalized on the drilling opportunities associated with the Great Northern acquisition.

	Three months ended December 31		Twelve months ended December 31	
($000)	2004	2003	2004	2003
Corporate acquisitions	–	–	291,084	137,622
Property acquisitions	3,764	3,107	10,351	26,928
Land acquisitions	4,248	487	10,344	2,310
Seismic	2,991	96	4,561	1,070
Drilling and completions	22,291	8,519	41,449	24,287
Production facilities	5,621	3,216	11,222	7,749
Head office	643	116	1,203	494
Subtotal	39,559	15,541	370,214	200,460
Dispositions	(306)	(6,953)	(505)	(9,284)
Net capital expenditures	39,253	8,588	369,709	191,176

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

The Trust is involved in certain legal actions that occurred in the normal course of business. The Trust is required to determine whether a contingent loss is probable and whether that loss can be reasonably estimated. When the loss has satisfied both criteria, it is charged to net income. Management is of the opinion that losses, if any, arising from such legal actions would not have a material effect on these financial statements.

The Trust leases its office premises through an arrangement deemed to be an operating lease for accounting purposes. As such, the Trust is not required to record its lease obligation as a liability nor does it record its leased premises as an asset. The estimated operating lease commitments for the Trust's leased office premises for the next five years are as follows:

($000)	
2005	1,398
2006	1,213
2007	1,252
2008	1,083
2009	934
Thereafter	934

RISK MANAGEMENT

The Trust's objective is to provide unitholders with stable cash distributions and strong overall returns. APF is committed to full-cycle internal development opportunities and selectively pursuing acquisitions identified to be accretive on a per unit basis to cash flow, production, reserves and net asset value as a means to achieving its objectives. The Trust has established a risk management framework in order to mitigate risks inherent in the oil and gas sector.

COMMODITY PRICE RISK

Commodity price risk is defined as fluctuations in crude oil, natural gas, and natural gas liquid prices. The Trust uses derivative instruments as part of its risk management approach to manage commodity price fluctuations and stabilize cash flows available for unitholder distributions and future development programs. At December 31, 2004, the Trust had recorded a $2.30 million unrealized loss on outstanding crude oil derivative instruments and a $2.06 million unrealized gain on outstanding natural gas derivative instruments.

Crude oil and natural gas derivative instruments outstanding at the end of 2004 are as follows:

Period	Commodity	Type of contract	Average daily quantity	Average daily price per bbl, GJ or mmbtu
January to March 2005	Crude oil	Swap	1,500 bbls	$U.S. 35.78
January to March 2005	Crude oil	Collar	1,000 bbls	$U.S. 38.00 to $U.S. 44.95
January to March 2005	Crude oil	Sold call	500 bbls	$U.S. 42.37 ($U.S. 3.19 premium)
April to June 2005	Crude oil	Swap	667 bbls	$U.S. 36.66
April to June 2005	Crude oil	Collar	2,000 bbls	$U.S. 39.25 to $U.S. 44.94
April to June 2005	Crude oil	Sold call	500 bbls	$U.S. 40.95 ($U.S. 3.45 premium)
July to September 2005	Crude oil	Collar	1,000 bbls	$U.S. 41.00 to $U.S. 51.30
January to March 2005	Natural gas	Sold call	5,000 GJ	$Cdn. 11.80
January to March 2005	Natural gas	Collar	5,000 GJ	$Cdn. 7.00 to $Cdn. 11.35
April to October 2005	Natural gas	Collar	5,000 mmbtu	$U.S. 6.50 to $U.S. 6.90
April to October 2005	Natural gas	Collar	10,000 GJ	$Cdn. 6.25 to $Cdn. 7.20

The following contracts were entered into subsequent to December 31, 2004:

Period	Commodity	Type of contract	Average daily quantity	Average daily price per unit
April to June 2005	Crude oil	Collar	1,000 bbls	U.S.$43.00 to U.S.$51.65
July to September 2005	Crude oil	Collar	2,500 bbls	U.S.$44.00 to U.S.$50.99
October to December 2005	Crude oil	Collar	1,500 bbls	U.S.$44.00 to U.S.$51.82
January to March 2006	Crude oil	Collar	2,000 bbls	U.S.$44.00 to U.S.$51.28
April to June 2006	Crude oil	Collar	500 bbls	U.S.$44.00 to U.S.$50.60
April to October 2005	Natural gas	Collar	10,000 GJ	Cdn.$6.00 to Cdn.$7.30
November 2005 to March 2006	Natural gas	Collar	10,000 GJ	Cdn.$6.50 to Cdn.$9.90

ELECTRICITY PRICE RISK

Electricity price risk is defined as fluctuations in input power prices charged to operating costs. The Trust's electricity cost management activities had an unrealized gain of $0.03 million at year end. APF assumed a fixed price electricity contract through the acquisition of Great Northern. At December 31, 2004, the Trust had a 2MW (7x24) contract with a fixed price of $46.40/MWh for calendar 2005; the forward price in the market for calendar 2005 was $49.00/MWh.

FOREIGN CURRENCY RISK

Foreign currency risk is the risk that a variation in the $U.S./$Cdn. exchange rate will negatively impact the Trust's operating and financial results. The Trust's currency risk management activities had an unrealized gain of $1.10 million at December 31, 2004. The derivative instruments currently outstanding are as follows:

Term	Type of contract	Amount ($U.S. 000)	Exchange rate ($U.S. / $Cdn.)
January to April 2005	Forward	5,000	1.3550
January to April 2005	Forward	5,000	1.3680
January to December 2005	Collar	5,000	1.2300 to 1.2700
January to December 2005	Collar	10,000	1.2000 to 1.2600
February to December 2005	Collar	10,000	1.2300 to 1.2700

The costless collar arrangements have counterparty call options on December 30, 2005 whereby the Trust's counterparty can extend the contract term for calendar 2006 at an average rate of 1.2740.

Interest rate risk

Interest rate risk is the risk that variations in interest rates will negatively impact the Trust's financial results. The Trust had entered into various derivative instruments to manage its interest rate exposure on debt instruments. At December 31, 2004, the Trust's interest rate risk management activities had an unrealized loss of $0.67 million related to the following fixed rate contracts:

Term	Amount ($000)	Interest rate
January 2005 to November 2005	20,000	3.58% plus stamping fee
January 2005 to May 2006	20,000	3.60% plus stamping fee
January 2005 to March 2007	20,000	3.58% plus stamping fee
January 2005 to September 2007	20,000	3.65% plus stamping fee

Production risk

Production risk relates to the Trust's ability to produce, process and transport crude oil and natural gas. To manage this risk to an acceptable level, the Trust performs regular and proactive maintenance on its wells, facilities and pipelines. The Trust operates approximately 85 percent of its production, which affords greater control over operations.

Natural decline and reserve replacement risk

Natural decline risk relates to the Trust's ability to replace reserves in excess of annual production declines through development activities such as drilling, well completions, well workovers and other capital activities. The Trust manages its business using a portfolio approach whereby capital is allocated across a number of areas so that significant capital is not risked on any one activity. Capital is spent only after strict economic criteria for production and reserve additions are assessed.

The Trust's reserves are evaluated on an annual basis by independent third-party consultants reporting to the Trust's Audit and Reserves Committee of the Board of Directors. The Trust's approach is to invest in mature, long-life properties with a high proved producing component combined with low-risk development opportunities where the reserve risk is generally lower and cash flows are more stable and predictable.

Acquisition risk

Acquisition risk arises when the Trust acquires producing properties as a means to growing its asset base. The Trust is proactive in seeking out corporate or property transactions that will be accretive on a per unit basis to cash flow, production, reserves, and net asset value. The cross-functional acquisition teams identify opportunities for value enhancement through operational efficiencies or strategic fit, and evaluate estimates against established acquisition and economic hurdle rates.

Environmental health and safety risk

Environment, health and safety risks relate primarily to field operations associated with oil and gas assets. To mitigate this risk, a preventative environmental, health and safety program is in place as well as operational loss insurance coverage. APF employees and contractors adhere to APF's environment, health and safety program, which is routinely reviewed and updated to ensure the Trust operates in a manner consistent with best practices in the industry. The Board of Directors is actively involved in the risk assessment and risk mitigation process.

Regulation, tax and royalty risk

Regulation, tax and royalty risk relates to changing government royalty regulations, income tax laws and incentive programs impacting the Trust's financial and operating results. The tax efficiency of the royalty trust model is contingent upon its status as a mutual fund trust under Canadian tax laws and, therefore, may be subject to unanticipated legislative and/or regulatory modification. Management and oversight committees, with the assistance of legal counsel, stay informed of proposed changes in laws and regulations and proactively respond to and plan for the effects that these changes.

Capital market risk

APF's ability to maintain its financial strength and liquidity is dependent upon its ability to access Canadian capital markets. If Canadian debt or equity markets were to become less accessible to the Trust, it may affect the ability of APF to continue to replace production and maintain distributions.

SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

Consolidation

These consolidated financial statements include the accounts of the Trust, Energy, LP and Tika and are referred to collectively as "APF" or "the Trust". Investments in jointly controlled companies and unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby the Trust's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Revenue Recognition

Revenue associated with the sale of crude oil, natural gas, and natural gas liquids owned by the Trust are recognized when title passes from the Trust to its customers.

Property, Plant and Equipment

APF uses the full cost method for oil and gas exploration, development and production activities as set out in CICA Accounting Guideline 16 ("AcG-16"), "Oil and Gas Accounting – Full Cost". The cost of acquiring oil and natural gas properties as well as subsequent development costs are capitalized and accumulated in a cost center. Maintenance and repairs are charged against income, and renewals and enhancements, which extend the economic life of the property, plant and equipment, are capitalized. Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would alter the rate of depletion by at least 20 percent.

AcG-16 requires that a ceiling test be performed at least annually to assess the carrying value of oil and gas assets. A cost center is tested for recoverability using undiscounted future cash flows from proved reserves and forward indexed commodity prices, adjusted for contractual obligations and product quality differentials. A cost center is written down to its fair value when its carrying value, less the cost of unproved properties, is in excess of the related undiscounted cash flows. Fair value is estimated using accepted present value techniques that incorporate risk and uncertainty when determining expected future cash flows. Unproved properties are excluded from the ceiling test calculation and subject to a separate impairment test.

Depreciation, Depletion and Accretion

In accordance with the full cost accounting method, all crude oil and natural gas acquisition, exploration, and development costs, including asset retirement costs, are accumulated in a cost center. The aggregate of net capitalized costs and estimated future development costs, less the cost of unproved properties and estimated salvage value, is amortized using the unit-of-production method based on current period production and estimated proved oil and gas reserves calculated using constant prices.

All other equipment is depreciated over the estimated useful life of the respective assets.

Oil and Gas Reserves

The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity prices and consider the timing of future expenditures. The Trust expects reserve estimates to be revised based on the results of future drilling activity, testing, production levels and economics of recovery based on cash flow forecasts.

Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of the acquired business. Net identifiable liabilities acquired include an estimate of future income taxes. In accordance with CICA Handbook Section 3062 ("HB 3062"), "Goodwill and Other Intangibles", goodwill for the reporting unit, the consolidated Trust, is tested at least annually for impairment. Impairment is charged to income during the period in which it is deemed to have occurred.

The test for impairment is the comparison of the book value of net assets to the fair value of the Trust. If the fair value of the Trust is less than its book value, the impairment loss is measured by allocating the fair value of the Trust to the identifiable assets and liabilities at their fair values. The excess of the Trust's fair value over the identifiable net assets is the implied fair value of goodwill. If this amount is less than the book value of goodwill, the difference is the impairment amount and would be charged to income during the period.

Income Taxes

The Trust is an *inter vivos* trust for income tax purposes. As such, the Trust is taxable on income that is not distributed or distributable to unitholders. As the Trust distributes all of its taxable income to the unitholders, no current provision for income taxes has been recorded. Should the Trust incur any income taxes, the funds available for distribution would be reduced accordingly.

The provision for income taxes is recorded in Energy using the liability method of accounting for income taxes. Future income taxes are recorded to the extent the accounting bases of assets and liabilities differ from their corresponding tax values using substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted during the period with the adjustment recognized in net income.

The determination of the Trust's income and other tax liabilities are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, actual income tax liabilities or recoveries may differ significantly from estimates.

Commitments and Contingencies

APF is involved in various legal claims associated with the normal course of operations. APF is required to determine whether a contingent loss is probable and whether that loss can be reasonably estimated. When the loss has satisfied both criteria it is charged to net income. Management is of the opinion that losses, if any, arising from such legal actions would not have a material effect on these financial statements.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

Asset Retirement Obligations

Effective January 1, 2004, APF retroactively adopted CICA Handbook Section 3110, "Asset Retirement Obligations" (ARO). The new standard requires that the fair value of an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made.

The present value of the asset retirement obligation is recognized as a liability with the corresponding asset retirement cost capitalized as part of property, plant and equipment. The asset retirement obligation will increase over time due to accretion and the asset retirement cost will be depreciated on a basis consistent with depreciation and depletion. APF previously used the unit-of-production method to match estimated future retirement costs with the revenues generated over the life of the petroleum and natural gas properties based on total estimated proved reserves and an estimated future liability.

The impact of this change has been disclosed in Note 3 to the consolidated financial statements.

Compensation Expense

Effective December 31, 2003, APF prospectively adopted CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments." The standard requires that equity instruments awarded to employees after December 31, 2002, be measured at fair value and recognized over the related period of service ("vesting period") with a corresponding increase to contributed surplus. When rights are exercised by employees and directors of the Trust, the consideration paid is recorded to the unitholders' investment account along with related non-cash compensation expense previously recognized in contributed surplus.

APF has established a Trust Unit Options Plan (the "Plan") and a Trust Unit Incentive Rights Plan (the "Rights Plan") for employees and independent directors that are described in Note 13 to the financial statements. The exercise price of the rights granted under the Rights Plan may be reduced in future periods based on future operating performance in accordance with the terms of the Rights Plan. The Trust uses a Black-Scholes option-pricing model to estimate the fair value of rights awarded under the Rights Plan as at the grant date. The fair value ascribed to awarded rights is not subsequently revised for any change in underlying assumptions. Compensation expense is adjusted prospectively for rights cancelled under the Rights Plan during the period.

Details of both the Options Plan and Rights Plan are disclosed in Note 13 and the impact of this change has been disclosed in Note 3 to the consolidated financial statements.

Derivative Instruments and Hedging Relationships

Effective January 1, 2004, APF prospectively adopted CICA Accounting Guideline 13 ("AcG-13"), "Hedging Relationships" and the amended Emerging Issues Committee 126 ("EIC-126"), "Accounting for Trading, Speculative or Non Trading Derivative Financial Instruments". In accordance with the new guideline, all unrealized derivative instruments that either do not qualify as a hedge under

AcG-13, or are not designated as a hedge, are recorded as a derivative asset or a derivative liability on the consolidated balance sheet with any changes in fair value during the period recognized in income. Prior to January 1, 2004, the Trust recognized gains and losses on derivative contracts at the time of settlement.

In order to apply hedge accounting, an entity must formally document the hedging arrangement and sufficiently demonstrate the effectiveness of the hedging relationship. Based on a review of the Trust's derivative position at January 1, 2004, the majority of derivative contracts did not qualify for hedge accounting.

APF's mark-to-market position on derivative contracts is disclosed in Note 7 and the transitional impact of this change has been disclosed in Note 3 to the consolidated financial statements.

Financial Instruments with a Conversion Feature

Effective December 31, 2004, APF retroactively adopted the revised CICA Handbook Section 3860 ("HB 3860"), "Financial Instruments - Presentation and Disclosure" for financial instruments that may be settled at the issuer's option in cash or its own equity instruments. The revised standard requires APF to classify the convertible debenture proceeds as either debt or equity based on fair value measurement and the substance of the contractual arrangement. The Trust previously presented the convertible debenture proceeds (net of financing costs) and related interest obligations as equity on the consolidated balance sheet on the basis that the Trust could settle its obligations in exchange for Trust units.

The Trust's obligation to make scheduled payments of principal and interest constitutes a financial liability under the revised standard and exists until the instrument is either converted or redeemed. The holders' option to convert the financial liability into Trust units is an embedded conversion option. The conversion option is presented as equity because it is the initial value ascribed to the holders' right to convert a financial liability into Trust units at the date of issuance. The sum of the liability and equity components is equal to the $50.0 million proceeds received from the convertible debenture issuance. Details of the convertible debentures are disclosed in Note 10 and the impact of this change on prior periods presented has been disclosed in Note 3 to the consolidated financial statements.

OUTLOOK

Strategy

APF emphasizes a full-cycle approach to its business and plans to continue with internal development opportunities as a means to enhancing its production base and ultimately creating value for unitholders. Consistent with its full-cycle approach, APF actively added to its undeveloped land position through crown land sales during 2004 in order to establish high-quality drilling prospects. The objective is to position APF so that production and reserves can be added independent of acquisition activity. In that regard, the Trust's ability to add production through the drill bit creates a competitive advantage over those competitors that have depleted their development inventories and are reliant upon acquisitions to build or maintain their production base.

APF will continue to pursue acquisitions that will be accretive on a per unit basis to cash flow, production, reserves and net asset value. APF is committed to maintaining stable cash distributions over the long-term. In order to mitigate the commodity price risk that is inherent to the oil and gas sector, APF will continue to actively hedge commodity prices. APF believes that over the long term, outlook for both crude oil and natural gas pricing remains strong.

2005 Capital Investment and Development Activities

Based on current estimates and assumptions, APF plans to focus its 2005 capital program in the following manner:

($000)	Drilling & development	Land & seismic	Total
Southeast Saskatchewan	8,554	1,300	9,854
Southern	7,952	2,000	9,952
Central	11,394	1,035	12,429
Western	5,781	3,300	9,081
CBM – Alberta	15,289	375	15,664
CBM – Wyoming	4,483	–	4,483
Total	53,453	8,010	61,463

In addition, the Trust anticipates spending $2.80 million on environmental health and safety initiatives throughout the year.

The Trust expects its 2005 core capital investment program to be funded from its DRIP, cash flow and proceeds from the divestiture of non-core assets.

Recent land acquisitions within the Western Business Unit ("Western") complement ongoing and planned internal development activities at APF's Paddle River properties. Coalbed methane opportunities exist in the Upper Mannville formation and APF is currently in the de-watering process at Corbett Creek.

The Central Business Unit ("Central") contains a large inventory of conventional and unconventional drilling opportunities. APF will continue to exploit new opportunities and undeveloped acres while continuing to focus internal development capital on the core Innisfail asset. CBM activity in the Horseshoe Canyon coals is expected to increase as APF continues to build its unconventional asset base.

A significant percentage of the upcoming year's capital budget will be targeted at Queensdale and Handsworth located within the Southeast Saskatchewan Business Unit ("Southeast Saskatchewan"). This area has historically generated excellent operating results and full cycle investment returns and is capable of generating excellent economics despite high natural decline rates.

APF is most active in its Southern Business Unit ("Southern"). The historical focus has been low productivity, long life shallow gas in the Milk River and Medicine Hat formations. Future development will move beyond shallow gas drilling to include deeper prospects at Countess, Turin and Carmangay.

2005 Production Volumes

The production outlook for 2005 will be principally impacted by weather, timing of new production and drilling activity. APF expects to average 18,000 to 18,500 boe/d of production based on its established capital budget of $61.46 million for fiscal 2005. Assumptions include drilling costs, well performance, operating costs, projected sales volumes, interest rates, foreign currency exchange rates and other factors that impact operations. These inputs can change significantly as a result of actual events and may result in material variances from the Trust's estimates.

The following table provides projected estimates for 2005 of the sensitivity of the Trust's cash flow to changes in a number of variables:

Variable	Assumption	Change	Impact on annual cash flow ($000)	Impact on cash flow per unit
Crude oil price ($U.S./bbl)	$42.00	$1.00	$3,010	$0.05
Natural gas price ($Cdn./mcf)	$6.60	$0.10	$1,730	$0.03
$U.S./$Cdn. exchange rate	$0.82	$0.01	$1,540	$0.02
Interest rate	5.0%	1.0%	$2,010	$0.03
Crude oil production (bbl/d)	8,500	100 bbl/d	$890	$0.01
Natural gas production (mcf/d)	58,000	1,000 mcf/d	$1,360	$0.02

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

Management is responsible for the preparation of the consolidated financial statements and the preparation of all other financial information included in the annual report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles, and where applicable, amounts based on management's best estimates and judgment.

Management has established procedures and systems of internal control designed to provide reasonable assurance that assets are safeguarded and that accurate financial information is produced in a timely manner.

The Board of Directors is responsible for reviewing and approving the consolidated financial statements and, through its Audit Committee, ensuring that management fulfills its responsibilities for financial reporting. The Audit Committee meets periodically with management and the external auditors to satisfy itself that each party is properly discharging its responsibilities. The Audit Committee reviews the consolidated financial statements and recommends their approval to the Board of Directors. PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, appointed by the unitholders of APF Energy Trust, have audited the consolidated financial statements in accordance with Canadian generally accepted auditing standards. PricewaterhouseCoopers LLP have full and free access to the Audit Committee.

Martin Hislop
Chief Executive Officer

Alan MacDonald
Vice President, Finance & Chief Financial Officer

Calgary, Alberta
February 25, 2005

AUDITORS' REPORT

To the Unitholders of APF Energy Trust

We have audited the consolidated balance sheets of APF Energy Trust as at December 31, 2004 and 2003 and the consolidated statements of operations and accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP
Chartered Accountants

Calgary, Alberta
February 25, 2005

CONSOLIDATED BALANCE SHEET

($000s except for per unit amounts) As at December 31	2004	2003 Restated (note 3)
ASSETS		
Current assets		
Cash	567	1,381
Accounts receivable	42,200	27,542
Derivative asset (note 7)	3,313	–
Other current assets	7,162	5,549
	53,242	34,472
Asset retirement fund	3,271	2,342
Goodwill (note 5)	118,478	48,230
Property, plant and equipment (note 6)	687,179	413,706
	862,170	498,750
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	52,677	36,698
Derivative liability (note 7)	3,141	–
Distribution payable (note 4)	9,415	5,963
	65,233	42,661
Future income taxes (note 9)	86,711	63,991
Long-term debt (note 8)	169,000	98,000
Convertible debentures (note 10)	47,697	47,719
Asset retirement obligations (note 11)	30,993	21,803
Derivative liability (note 7)	335	–
	399,969	274,174
UNITHOLDERS' EQUITY		
Unitholders' investment account (note 12)	610,194	324,318
Contributed surplus (note 13)	289	1,241
Accumulated earnings	126,862	77,226
Accumulated distributions (note 4)	(276,293)	(179,363)
Convertible debenture conversion feature (note 10)	1,149	1,154
	462,201	224,576
	862,170	498,750

Contractual obligations and commitments (note 16)

See accompanying notes to consolidated financial statements

Approved by the Board of Directors

Martin Hislop
Director

Donald Engle
Director

CONSOLIDATED STATEMENT OF OPERATIONS AND ACCUMULATED EARNINGS

($000s except for per unit amounts)

For the year ended December 31	2004	2003
		Restated (note 3)
Revenue		
Oil and gas	253,213	173,196
Realized derivative loss – net (note 7)	(16,329)	(3,565)
Unrealized derivative gain – net (note 7)	223	–
Royalties expense, net of ARTC	(47,710)	(32,473)
Transportation	(5,245)	(4,174)
	184,152	132,984
Expenses		
Operating	51,788	32,370
General and administrative	10,635	10,023
Interest on long-term debt (note 8)	5,405	4,171
Convertible debenture interest and financing charges (note 10)	5,263	2,669
Depletion, depreciation and accretion	85,997	53,389
Unit-based compensation expense (recovery) (note 13)	(877)	1,241
Capital and other taxes	3,321	2,720
	161,532	106,583
Income before future income taxes	22,620	26,401
Recovery of future income taxes (note 9)	(27,016)	(14,207)
Net income	49,636	40,608
Accumulated earnings – beginning of period, as previously reported	77,226	35,589
Change in accounting policy (note 3)	–	1,029
Accumulated earnings – end of period, as restated	126,862	77,226
Net income per unit – basic	$ 1.02	$ 1.31
Net income per unit – diluted (1)	$ 1.02	$ 1.29

(1) Convertible debenture interest has been added back to net income to calculate net income per unit – diluted.

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENT OF CASH FLOWS

($000s except for per unit amounts)

For the year ended December 31	2004	2003
		Restated (note 3)
Cash flows from operating activities		
Net income	49,636	40,608
Items not affecting cash		
Depletion, depreciation and accretion	85,997	53,389
Debenture accretion and amortization of deferred financing charges	692	362
Future income taxes	(27,016)	(14,207)
Unrealized derivative gain – net (note 7)	(223)	–
Unit-based compensation expense (recovery) (note 13)	(877)	1,241
Asset retirement expenditures (note 11)	(1,083)	(374)
Cash flow from operations	107,126	81,019
Net change in non-cash working capital items (note 15)	(10,473)	5,823
Asset retirement fund contribution – net	(929)	(1,558)
Net cash provided by operating activities	95,724	85,284
Cash flows from investing activities		
Corporate acquisitions (note 5)	(65,405)	(58,259)
Additions to property, plant and equipment	(68,779)	(33,601)
Purchase of oil and natural gas properties	(10,351)	(29,238)
Proceeds on sale of properties	505	9,284
Changes in non-cash working capital – investing items	5,205	2,961
Net cash used in investing activities	(138,825)	(108,853)
Cash flows from financing activities		
Issue of units for cash	90,451	55,670
Issue of units for cash under DRIP	33,895	1,329
Issue of units for cash upon exercise of stock options/rights	3,799	1,749
Net proceeds (repayment) of convertible debentures	–	47,681
Unit issue costs	(5,270)	(3,467)
Net proceeds (repayment) of long-term debt	7,126	(12,920)
Cash distributions, net of distribution reinvestment	(91,166)	(68,440)
Changes in non-cash working capital – financing items	3,452	2,398
Net cash provided by financing activities	42,287	24,000
Change in cash during the period	(814)	431
Cash – beginning of period	1,381	950
Cash – end of period	567	1,381

Supplemental information (note 14)

See accompanying notes to consolidated financial statements

December 31, 2004 and 2003

NOTE 1. BASIS OF PRESENTATION

APF Energy Trust (the "Trust")

The Trust is an open-end investment trust under the laws of the Province of Alberta.

APF Energy Inc. ("Energy")

Energy was incorporated and organized for the purpose of acquiring, developing, exploiting and disposing of oil and natural gas properties, including certain initial properties and granting a royalty thereon to the Trust.

APF Energy Limited Partnership ("LP")

LP was formed for the purpose of acquiring, developing, exploiting and disposing of oil and natural gas properties and granting a royalty thereon to the Trust.

Tika Energy Inc. ("Tika")

Tika is a wholly owned subsidiary of Energy and was incorporated in Wyoming for the purpose of acquiring, developing, exploiting and disposing of coalbed methane gas properties in the United States.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

These consolidated financial statements include the accounts of the Trust, Energy, LP and Tika and are referred to collectively as "APF" or "the Trust". Investments in jointly controlled companies and unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby the Trust's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Revenue recognition

Revenue associated with the sale of crude oil, natural gas and natural gas liquids owned by the Trust are recognized when title passes from the Trust to its customers.

Property, plant and equipment

APF uses the full cost accounting method for oil and gas exploration, development and production activities as set out in CICA Accounting Guideline 16 ("AcG-16"), "Oil and Gas Accounting – Full Cost". The cost of acquiring oil and natural gas properties as well as subsequent development costs are capitalized and accumulated in a cost center. Maintenance and repairs are charged against income, and renewals and enhancements, which extend the economic life of the property, plant and equipment, are capitalized. Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would alter the rate of depletion by at least 20 percent.

All other equipment is carried at the lesser of depreciated cost and fair value.

Ceiling test

AcG-16 requires that a ceiling test be performed at least annually to assess the carrying value of oil and gas assets. A cost centre is tested for recoverability using undiscounted future cash flows from proved reserves and forward indexed commodity prices, adjusted for contractual obligations and product quality differentials. A cost centre is written down to its fair value when its carrying value, less the cost of unproved properties, is in excess of the related undiscounted cash flows. Fair value is estimated using accepted present value techniques that incorporate risk and uncertainty when determining expected future cash flows. Unproved properties are excluded from the ceiling test calculation and subject to a separate impairment test.

Depletion, depreciation and accretion

In accordance with the full cost accounting method, all crude oil and natural gas acquisition, exploration, and development costs, including asset retirement costs, are accumulated in a cost center. The aggregate of net capitalized costs and estimated future development costs, less the cost of unproved properties and estimated salvage value, is amortized using the unit-of-production method based on current period production and estimated proved oil and gas reserves calculated using constant prices.

All other equipment is depreciated over the estimated useful life of the respective assets.

Oil and gas reserves

The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity prices, and consider the timing of future expenditures. The Trust expects reserve estimates to be revised based on the results of future drilling activity, testing, production levels and economics of recovery based on cash flow forecasts.

Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of the acquired business. Net identifiable liabilities acquired include an estimate of future income taxes. In accordance with CICA Handbook Section 3062 ("HB 3062"), "Goodwill and Other Intangibles", goodwill for the reporting unit, the consolidated Trust, is tested at least annually for impairment. Impairment is charged to income during the period in which it is deemed to have occurred.

The test for impairment is the comparison of the book value of net assets to the fair value of the Trust. If the fair value of the Trust is less than its book value, the impairment loss is measured by allocating the fair value of the Trust to the identifiable assets and liabilities at their fair values. The excess of the Trust's fair value over the identifiable net assets is the implied fair value of goodwill. If this amount is less than the book value of goodwill, the difference is the impairment amount and would be charged to income during the period.

Unit-based compensation expense

Effective December 31, 2003, the Trust prospectively adopted CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments." The standard requires that equity instruments awarded to employees after December 31, 2002 be measured at fair value and recognized over the related vesting period with a corresponding increase to contributed surplus. When rights are exercised by employees and directors of the Trust, the consideration paid is recorded to the unitholders' investment account along with related non-cash compensation expense previously recognized in contributed surplus.

APF has established a Trust Units Options Plan (the "Plan") and a Trust Unit Incentive Rights Plan (the "Rights Plan") for employees and independent directors that are described in Note 13. The exercise price of the rights granted under the Rights Plan may be reduced in future periods based on future operating performance in accordance with the terms of the Rights Plan.

The Trust uses a Black-Scholes option-pricing model to estimate the fair value of rights awarded under the Rights Plan at the grant date. The fair value ascribed to awarded rights is not subsequently revised for any change in underlying assumptions. Unit-based compensation expense is adjusted prospectively for rights cancelled under the Rights Plan during the period.

The new accounting standard resulted in the Trust recognizing an expense of $1.24 million for the year ended December 31, 2003, with a corresponding increase to contributed surplus. In conformity with the amended accounting standard, the Trust has elected to disclose pro forma results for equity instruments awarded to employees prior to January 1, 2003, as if CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" had been adopted retroactively.

There was no impact on the Trust's cash flow as a result of adopting the new standard. See Note 13 for additional information on compensation plans.

Income taxes

The Trust is an *inter vivos* trust for income tax purposes. As such, the Trust is taxable on income that is not distributed or distributable to unitholders. As the Trust distributes all of its taxable income to the unitholders no current provision for income taxes has been recorded. Should the Trust incur any income taxes, the funds available for distribution would be reduced accordingly.

The provision for income taxes is recorded in Energy using the liability method of accounting for income taxes. Future income taxes are recorded to the extent the accounting bases of assets and liabilities differ from their corresponding tax values using substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted during the period with the adjustment recognized in net income.

The determination of the Trust's income and other tax liabilities are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, actual income tax liabilities or recoveries may differ significantly from estimates.

Trust unit calculations

The Trust applies the treasury stock method to determine the dilutive effect of Trust unit rights and Trust unit options. Under the treasury stock method, outstanding and exercisable instruments that will have a dilutive effect are included in per unit – diluted calculations, ordered from most dilutive to least dilutive.

The dilutive effect of convertible debentures is determined using the "if-converted" method whereby if the current market price per unit is in excess of the stated conversion price per unit the weighted-average number of potential units assumed issued are included in the per unit – diluted calculations. The units issued upon conversion are included in the denominator of per unit – basic calculations from the date of conversion. Consequently, units assumed issued are weighted for the period the convertible debentures were outstanding, and units actually issued are weighted for the period the units were outstanding.

Measurement uncertainty

The timely preparation of financial statements in conformity with Canadian generally accepted accounting principles ("GAAP") requires that management make estimates and assumptions and use judgment regarding assets, liabilities, revenues, and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion, and amortization, asset retirement costs and obligations, and amounts used for ceiling test and impairment calculations are based on estimates of oil and natural gas reserves and future costs required to develop those reserves. By their nature, these estimates are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

NOTE 3. CHANGES IN ACCOUNTING POLICIES

Asset retirement obligations

Effective January 1, 2004, the Trust retroactively adopted CICA Handbook Section 3110, "Asset Retirement Obligations" (ARO). The standard requires that the fair value of an asset retirement obligation be recognized in the period in which it is incurred. The present value of the asset retirement obligation is recognized as a liability with the corresponding asset retirement cost capitalized as part of property, plant and equipment. The asset retirement obligation will increase over time due to accretion and the asset retirement cost will be depreciated on a basis consistent with depreciation and depletion. APF previously used the unit-of-production method to match estimated future retirement costs with the revenues generated over the life of the petroleum and natural gas properties based on total estimated proved reserves and an estimated future liability.

The following table summarizes the impact of the new standard on the 2003 comparative period:

	As at and for the year ended December 31, 2003		
($000s except for per unit amounts)	As reported	Change	As restated
Consolidated Balance Sheet			
Assets			
Property, plant, and equipment	401,286	12,420	413,706
Liabilities			
Future income taxes	64,222	(231)	63,991
Asset retirement obligation	–	21,803	21,803
Site restoration liability	10,410	(10,410)	–
Unitholders' Equity			
Opening accumulated earnings	35,589	1,029	36,618
Consolidated Statement of Operations			
Depletion, depreciation, and accretion	50,417	2,972	53,389
Site restoration	3,327	(3,327)	–
Recovery of future income taxes	(14,333)	126	(14,207)

See Note 11 for additional information on asset retirement obligations.

Derivative instruments and hedging relationships

Effective January 1, 2004, the Trust prospectively adopted CICA Accounting Guideline 13 ("AcG-13"), "Hedging Relationships" and the amended Emerging Issues Committee Abstract 128, "Accounting for Trading, Speculative or Non Trading Derivative Financial Instruments". In accordance with these standards, all unrealized derivative instruments that either do not qualify as a hedge under AcG-13, or are not designated as a hedge, are recorded as a derivative asset or a derivative liability on the consolidated balance sheet with any changes in fair value during the period recognized in income. Prior to January 1, 2004, the Trust recognized gains and losses on derivative contracts at the time of settlement.

In order to apply hedge accounting, an entity must formally document the hedging arrangement and sufficiently demonstrate the effectiveness of the hedging relationship. Based on a review of the Trust's derivative position at January 1, 2004, the majority of derivative contracts did not qualify for hedge accounting. Consequently, the Trust recorded $1.30 million liability as an estimate for the fair value of its derivative position on January 1, 2004, which was comprised of a $0.40 million unrealized loss on crude oil and natural gas derivative instruments and a $0.90 million unrealized loss on interest rate swaps. In accordance with the transitional provisions of the new guideline, the Trust recorded a corresponding deferred derivative loss, which was amortized into income during 2004 upon settlement of the underlying derivative instruments. There was no impact on the Trust's cash flow as a result of adopting this new guideline. See Note 7 for additional disclosure on derivative instruments.

Financial instruments with a conversion feature

Effective December 31, 2004, the Trust retroactively adopted the revised CICA Handbook Section 3860 ("HB 3860"), "Financial Instruments - Presentation and Disclosure" for financial instruments that may be settled at the issuer's option in cash or its own equity. The revised standard requires the Trust to classify proceeds from convertible debentures issued on July 3, 2003 as either debt or equity based on fair value measurement and the substance of the contractual arrangement. The Trust previously presented the convertible debenture proceeds (net of financing costs) and related interest obligations as equity on the consolidated balance sheet on the basis that the Trust could settle its obligations in exchange for Trust units.

The Trust's obligation to make scheduled payments of principal and interest constitutes a financial liability under the revised standard and exists until the instrument is either converted or redeemed. The holders' option to convert the financial liability into Trust units is an embedded conversion option. Gross proceeds of $50 million received at issuance were allocated $48.82 million to debt and $1.18 million to the equity conversion feature. At December 31, 2003, after conversions and accretion, the debt component was $47.72 million and the equity component was $1.15 million. Underwriter costs and professional fees associated with the issuance totalled $2.32 million and will be amortized into income on a straight-line basis over the term of the instrument. At December 31, 2003, $2.04 million was included in other current assets.

The following table summarizes the impact of the revised standard on the 2003 comparative period:

	As at and for the year ended December 31, 2003		
($000s except for per unit amounts)	As reported	Change	As restated
Consolidated Balance Sheet			
Assets			
Other current assets (includes deferred financing)	3,506	2,043	5,549
	3,506	2,043	5,549
Liabilities			
Accounts payable and accrued liabilities	36,711	(13)	36,698
Convertible debentures	–	47,719	47,719
	36,711	47,706	84,417
Unitholders' Equity			
Unitholders investment account	324,317	1	324,318
Convertible debentures	46,466	(46,466)	–
Accumulated interest on convertible debentures	(2,317)	2,317	–
Convertible debenture conversion feature	–	1,154	1,154
	368,466	(42,994)	325,472
Consolidated Statement of Operations			
Convertible debenture interest and financing charges	–	2,669	2,669

There was no impact on the Trust's cash flow as a result of adopting the revised standard. See Note 10 for additional information on convertible debentures.

NOTE 4. DISTRIBUTIONS

	For the year ended December 31	
($000s except for per unit amounts)	2004	2003
		Restated (note 3)
Cash flow from operations	107,126	81,019
Add (deduct):		
Abandonment fund contributions	(2,012)	(1,932)
Cash retained to fund operations	(6,368)	(21,556)
Working capital change	(1,816)	11,182
Distributions	96,930	68,713
Distributed to date	87,515	62,750
Distribution payable	9,415	5,963
	96,930	68,713
Opening accumulated distributions	179,363	110,650
Closing accumulated distributions	276,293	179,363
Actual distribution declared per unit	$2.00	$2.20

NOTE 5. ACQUISITIONS

On June 4, 2004, the Trust acquired the issued and outstanding shares of Great Northern Exploration Ltd. ("Great Northern"). During 2003, APF acquired the issued and outstanding shares of Hawk Oil Inc. ("Hawk Oil") on February 5, Nycan Energy Corp. ("Nycan") on April 28, and CanScot Resources Ltd. ("CanScot") on September 26. The purchase price allocation for each acquisition and components of consideration paid is as follows:

	Great Northern	CanScot	Nycan	Hawk Oil
($000)	2004	2003	2003	2003
Net assets acquired at assigned values:				
Working capital deficiency	(4,857)	178	928	(634)
Property, plant and equipment	255,941	32,980	47,495	57,146
Undeveloped land and seismic	22,943	–	–	–
Goodwill	70,248	16,884	8,792	11,078
Debt assumed	(63,874)	(6,150)	(8,870)	(7,900)
Financial derivatives	(1,103)	–	–	–
Asset retirement obligation	(7,866)	(388)	(580)	(263)
Future income taxes	(49,084)	(7,399)	(13,266)	(18,266)
Net assets acquired	222,348	36,105	34,499	41,161
Purchase price comprised of:				
Trust units	156,943	15,433	–	37,710
Cash	63,250	–	–	2,856
Bank debt	–	19,689	34,374	–
Acquisition costs	2,155	983	125	595
Purchase price	222,348	36,105	34,499	41,161

The following table highlights investing cash flows associated with corporate acquisitions completed in 2004 and 2003:

	Great Northern	CanScot	Nycan	Hawk Oil
($000)	2004	2003	2003	2003
Net assets acquired	222,348	36,105	34,499	41,161
Deduct:				
Debt assumed (cash acquired)	–	(156)	(212)	5
Trust units issued	(156,943)	(15,433)	–	(37,710)
Net cash flows from corporate acquisitions	65,405	20,516	34,287	3,456

NOTE 6. PROPERTY, PLANT AND EQUIPMENT

($000)	2004	2003
Property, plant, and equipment	907,819	548,229
Accumulated depletion, depreciation, and accretion	(220,640)	(134,523)
	687,179	413,706

Future development costs of $48.22 million (2003 – $25.00 million) related to total proved reserves were included as depletable costs in the calculation of depletion, depreciation and accretion. Costs related to unproved properties totalled $28.45 million (2003 – $10.80 million) and were excluded from depletable costs. All costs of unproved properties, net of any associated revenues, have been capitalized. Ultimate recoverability of these costs will be dependent upon the finding of proved oil and natural gas reserves. The Trust performed a separate impairment review of assets excluded from the ceiling test and determined that $nil (2003 – $nil) should be charged to income during the year.

The Trust capitalized $0.50 million (2003 – $0.46 million) of administrative costs during the year associated with coalbed methane projects considered to be in the pre-production stage.

The prices used in the ceiling test evaluation of the Trust's natural gas, crude oil and natural gas liquids reserves at December 31, 2004 were as follows:

Year	WTI Oil ($U.S./bbl)	Foreign Exchange ($U.S./$Cdn.)	WTI Oil ($Cdn./bbl)	AECO Gas ($Cdn./mmbtu)
2005	42.76	1.1667	48.95	6.43
2006	40.56	1.1931	47.37	6.56
2007	39.44	1.2202	47.26	6.28
2008	37.77	1.2561	46.74	6.04
2009	37.14	1.2961	47.31	5.83
2010 – 2016 (1)	37.41	1.2961	47.56	5.87
Remainder (2)	2.00%	1.2961	2.00%	2.00%

(1) Represents the average for the period noted

(2) Percentage change represents the annual change each year from 2014 to the end of the reserve life

NOTE 7. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Trust has entered into various derivative instruments and physical contracts to manage fluctuations in commodity prices, foreign currency exchange rates, utility prices, and interest rates in the normal course of operations. A derivative instrument meets the definition of a financial instrument because it involves the exchange of financial assets, usually cash, and not the delivery or acceptance of oil and gas inventory. Conversely, a physical contract is not a financial instrument because it involves the delivery or acceptance of physical product. In conformity with AcG-13 and EIC 128 (see note 3), the following information only presents positions related to financial instruments.

The estimated fair value of unrealized derivative instruments is reported on the consolidated balance sheet with any change in the unrealized positions recorded to income. The following is a summary of the change in unrealized amounts from January 1, 2004 to December 31, 2004:

($000)	Deferred derivative loss recognized on transition	Total realized gain/(loss)	Total gain/(loss)
Fair value of contracts, January 1, 2004	1,300		(1,300)
Fair value of derivative contracts entered into during the period			(14,806)
Fair value of derivative contracts realized during the period		(16,329)	16,329
Fair value of contracts, December 31, 2004			223
Premiums received on sold call options			(386)
FV of contracts and premiums received, December 31, 2004			(163)

The following is a summary of unrealized fair value financial positions by risk management activity at December 31, 2004:

($000)	Total unrealized gain/(loss)
Commodity price	
Crude oil	(2,298)
Natural gas	2,059
Utilities	32
Foreign currency	1,103
Interest rate	(673)
	223
Premiums received on sold call options	(386)
	(163)

The following highlights the balance sheet classification of unrealized fair value financial positions at December 31, 2004:

($000)	Unrealized asset (liability)
Current asset	3,313
Long-term asset	–
Current liability	(3,141)
Long-term liability	(335)
	(163)

Commodity price risk

Commodity price risk is defined as fluctuations in crude oil, natural gas, and natural gas liquid prices. The Trust uses derivative instruments as part of its risk management approach to manage commodity price fluctuations and stabilize cash flows available for unitholder distributions and future development programs. At December 31, 2004, the Trust had recorded a $2.30 million unrealized loss on outstanding crude oil derivative instruments and a $2.06 million unrealized gain on outstanding natural gas derivative instruments.

Crude oil and natural gas derivative instruments outstanding at the end of 2004 are as follows:

Period	Type of commodity	Average contract	Average daily daily quantity	Price per bbl, GJ or mmbtu
January to March 2005	Crude oil	Swap	1,500 bbls	$U.S. 35.78
January to March 2005	Crude oil	Collar	1,000 bbls	$U.S. 38.00 to $U.S. 44.95
January to March 2005	Crude oil	Sold call	500 bbls	$U.S. 42.37 ($U.S. 3.19 premium)
April to June 2005	Crude oil	Swap	667 bbls	$U.S. 36.66
April to June 2005	Crude oil	Collar	2,000 bbls	$U.S. 39.25 to $U.S. 44.94
April to June 2005	Crude oil	Sold call	500 bbls	$U.S. 40.95 ($U.S. 3.45 premium)
July to September 2005	Crude oil	Collar	1,000 bbls	$U.S. 41.00 to $U.S. 51.30
January to March 2005	Natural gas	Sold call	5,000 GJ	$Cdn. 11.80
January to March 2005	Natural gas	Collar	5,000 GJ	$Cdn. 7.00 to $Cdn. 11.35
April to October 2005	Natural gas	Collar	5,000 mmbtu	$U.S. 6.50 to $U.S. 6.90
April to October 2005	Natural gas	Collar	10,000 GJ	$Cdn. 6.25 to $Cdn. 7.20

Electricity price risk

The Trust's electricity cost management activities had an unrealized gain of $0.03 million at year end. APF had assumed a fixed price electricity contract through the acquisition of Great Northern. At December 31, 2004, the Trust had a 2MW (7x24) contract with a fixed price of $46.40/MWh for calendar 2005.

Foreign currency risk

The Trust's foreign currency risk management activities had an unrealized gain of $1.10 million at year end. Foreign currency risk is the risk that a variation in the U.S./Cdn. exchange rate will negatively impact the Trust's operating and financial results. At December 31, 2004, the Trust had entered into contracts to sell U.S. dollars at a fixed rate in exchange for Canadian dollars as follows:

Term	Type of Contract	Amount ($U.S. 000)	Exchange rate ($U.S. / $Cdn.)
January to April 2005	Forward	5,000	1.3550
January to April 2005	Forward	5,000	1.3680
January to December 2005	Collar	5,000	1.2300 to 1.2700
January to December 2005	Collar	10,000	1.2000 to 1.2600

The costless collar arrangements have counterparty call options on December 30, 2005 whereby the Trust's counterparty can extend the $5.00 million contract term for calendar 2006 at 1.3100 and the $10.00 million contract term for calendar 2006 at 1.2700.

Interest rate risk

The Trust's interest rate risk management activities had an unrealized loss of $0.67 million at year end. The Trust had entered into various derivative instruments to manage its interest rate exposure on debt instruments. At December 31, 2004 the Trust had fixed the interest rate on a portion of its debt as follows:

Term	Amount ($000)	Interest rate
January 2005 to November 2005	20,000	3.58% plus stamping fee
January 2005 to May 2006	20,000	3.60% plus stamping fee
January 2005 to March 2007	20,000	3.58% plus stamping fee
January 2005 to September 2007	20,000	3.65% plus stamping fee

Fair value of financial assets and liabilities

The fair values of financial instruments presented on the consolidated balance sheet, other than long-term borrowings, approximate their carrying amount due to the short-term nature of those instruments. The estimated fair values of long-term borrowings approximated its fair value due to the floating rate of interest charged under the facilities.

NOTE 8. LONG-TERM DEBT

At December 31, 2004, APF had a revolving credit and term facility for $200 million (2003 – $150 million) with a syndicate of Canadian financial institutions. The facility may be drawn down or repaid at any time but there are no scheduled repayment terms. The credit facility bears interest based on a sliding scale tied to APF's debt-to-cash flow ratio: from a minimum of the bank's prime rate to a maximum of the bank's prime rate plus 1.625 percent (2003 – 0.125 to 1.625 percent) or where available, at Banker's acceptances rates plus a stamping fee of 1.00 to 2.25 percent (2003 – 1.125 to 2.00 percent). The facility contains an option to extend the revolving period for an additional 364 days at the option of the lenders upon notice from the Trust no earlier than 180 days and no less than 90 days prior to the end of the initial revolving period, being October 31, 2005. If not extended, the outstanding principal converts to a one-year non-revolving reducing loan for a term of one year. From the date of conversion to a one-year term facility, APF will pay one-sixth of the outstanding principal after 180 days and one-twelfth of the outstanding principal every 90 days thereafter.

The debt is collateralized by a $300 million demand debenture containing a first fixed charge on all crude oil and natural gas assets of APF as required by the lenders and a floating charge on all other property together with a general assignment of book debts. At December 31, 2004, the interest rate was bank prime of 4.25 percent plus 0.125 percent (2003 – 4.5 percent plus 0.125 percent).

NOTE 9. INCOME TAXES

The Trust applies substantively enacted income tax rates to derive its future income tax liability and the related provision (recovery) during the year. The Trust recorded a future income tax recovery of $27.02 million during the year (2003 – $14.21 million). The acquisition of Great Northern increased the future tax liability by $49.08 million resulting from temporary differences between tax bases and the fair value assigned to assets and liabilities acquired.

Federal corporate income tax rate reductions received Royal Accent during 2003. The applicable tax rate on resource income will ultimately be reduced from 28 per cent to 21 per cent over a five-year period, provide for the deduction of crown royalties and eliminate the deduction for resource allowance. The tax provision differs from the amount computed by applying the combined Canadian federal and provincial income tax statutory rates to income before future income tax recovery as follows:

($000)	2004	2003
Income before income taxes	22,620	26,401
Statutory tax rate	40.32%	42.75%
Expected tax provision (recovery)	9,120	11,286
Adjustments:		
Net income of the Trust	(26,191)	(19,886)
Resource allowance	(1,625)	(2,250)
Non-deductible crown charges	2,056	669
Capital tax	972	1,163
Rate reduction	(2,088)	(3,717)
Revision to tax pool estimates	(8,972)	–
Other	(288)	(1,472)
Recovery of future income taxes	(27,016)	(14,207)
Future tax liability comprised of:		
Accounting basis for capital assets in excess of tax basis	102,663	80,269
Asset retirement obligations	(11,197)	(7,775)
Derivative contracts	(59)	–
Future tax losses likely to be utilized	(4,696)	(8,503)
	86,711	63,991

The petroleum and natural gas properties and facilities owned by Energy and LP have an approximate tax bases of $185.00 million (2003 – $70.00 million) available for future use as deductions from taxable income. Included in the tax bases are non-capital loss carry forwards of $6.60 million (2003 – $22.30) which expire during years 2005 through 2010. No current income taxes were paid or payable in 2004 or 2003.

Taxable income of the Trust is comprised of income from royalties, adjusted for crown royalties and resource allowance, less deductions for Canadian oil and natural gas property expense (COGPE), which is claimed at a rate of 10 percent on a declining balance basis and issue costs which are claimed at 20 percent per year on a straight-line basis. Any losses that occur in the Trust must be retained in the Trust and may be carried forward and deducted from taxable income for a period of seven years. The tax bases held within the Trust at December 31, 2004 was $214.00 million (2003 – $122.30 million).

NOTE 10. CONVERTIBLE DEBENTURES

On July 3, 2003, APF issued $50.0 million of 9.40 percent unsecured subordinated convertible debentures ("convertible debentures") for proceeds of $50.0 million ($47.7 million net of issue costs). Interest is paid semi-annually on January 31 and July 31 and the instruments mature on July 31, 2008.

The debentures are convertible at the holder's option into fully paid and non-assessable Trust units at any time prior to July 31, 2008, at a conversion price of $11.25 per Trust unit. The holder will receive accrued and unpaid interest up to and including the conversion date. The debentures are not redeemable by the Trust before July 31, 2006, except under certain circumstances. The convertible debentures become redeemable at $1,050 per convertible debenture, in whole or in part, after July 31, 2006 and redeemable at $1,025 after July 31, 2007 and before maturity.

The convertible debentures are a debt security with an embedded conversion option and the following summarizes the accounting for the principal amount of the convertible debentures since their issuance:

($000)	Liability component	Equity component	Total
Issued on July 3, 2003	48,817	1,183	50,000
Accretion of liability during 2003	89	–	89
Conversions into Trust units during 2003	(1,187)	(29)	(1,216)
Carrying value at December 31, 2003	47,719	1,154	48,873
Accretion of liability during 2004	193	–	193
Conversions into Trust units during 2004	(215)	(5)	(220)
Carrying value at December 31, 2004	47,697	1,149	48,846

NOTE 11. ASSET RETIREMENT OBLIGATIONS

The following table presents the reconciliation of the beginning and ending aggregate asset retirement obligation associated with the retirement of oil and gas properties:

($000)	2004	2003
Asset retirement obligation, beginning of year	21,803	12,961
Liabilities acquired	7,866	4,673
Liabilities incurred	834	3,249
Liabilities settled	(1,083)	(374)
Accretion expense	1,573	1,294
Asset retirement obligation, end of year	30,993	21,803

The total undiscounted amount of estimated cash flows required to settle the obligation is $108.29 million (2003 – $70.72 million), which has been discounted using a credit-adjusted risk free rate of eight percent and an inflation factor of one and one-half percent. Most of these obligations are not expected to be paid for several years, or decades, in the future and will be funded from general company resources and the fund reserved for site reclamation and abandonment. The abandonment fund is currently funded at $0.53 million per quarter through cash flow from operations.

NOTE 12. UNITHOLDERS' INVESTMENT ACCOUNT

The per unit calculations for the year ended December 31, 2004 was based on weighted average Trust units outstanding of 48.49 million (2003 – 30.97 million). In computing net income per unit – diluted, 0.33 million units (2003 – 0.33 million) were added to the weighted average number of units outstanding for the year, reflecting the dilutive effect of employee options and rights. An additional 4.32 million Trust units (2003 – 2.18 million) were added to the weighted average number of units outstanding for the year relating to the assumed conversion of debentures. Interest on debentures assumed to be converted into Trust units totalled $5.26 million (2003 – $2.67 million) and was added back to net income for per unit – diluted calculations.

	December 31, 2004		December 31, 2003	
Trust units	Units (000)	($000)	Units (000)	($000)
Balance – beginning of period	34,074	324,318	22,942	214,405
Corporate acquisitions (note 5)	12,885	156,943	5,333	53,143
Issued for cash	7,877	90,451	5,352	55,670
Cost of units issued	–	(5,270)	–	(3,467)
Regular DRIP	516	5,764	24	273
Premium DRIP	3,031	33,895	117	1,329
Issued on conversion of debentures	19	220	108	1,216
Issued on exercise of options/rights	442	3,799	199	1,749
Allocated from contributed surplus	–	74	–	–
Balance – end of period	58,845	610,194	34,074	324,318

Unitholders' rights plan

In 2003, the Trust created a Unitholders' Rights Plan and authorized the issuance of one right in respect of each Trust unit outstanding. Each right would entitle a unitholder under certain circumstances to acquire upon payment of an exercise price of $50.00, the number of Trust units having an aggregate market price equal to twice the exercise price of the rights.

Units issued for cash

The Trust issued Trust units on two separate occasions: 4.77 million Trust units at $11.60 per unit for gross proceeds of $55.27 million on February 4, 2004; and 3.10 million Trust units at $11.30 per unit for gross proceeds of $35.03 million on September 8, 2004.

Distribution reinvestment program

Commencing December 2003, the Trust initiated a distribution reinvestment plan ("DRIP"). The DRIP permits eligible unitholders to direct their distributions to the purchase of additional units at 95 percent of the average market price as defined in the plan ("Regular DRIP"). The premium distribution component permits eligible unitholders to elect to receive 102 percent of the cash the unitholder would otherwise have received on the distribution date ("Premium DRIP"). Participation in the Regular DRIP and Premium DRIP is subject to proration by the Trust. Unitholders who participate in either the Regular DRIP or the Premium DRIP are also eligible to participate in the optional unit purchase plan as defined in the DRIP.

NOTE 13. UNIT-BASED COMPENSATION PLANS

APF has established a Trust Units Options Plan (the "Plan") and a Trust Unit Incentive Rights Plan (the "Rights Plan") for employees and independent directors. Pursuant to the Plan arrangement, employees, directors and long-term consultants may be granted options to purchase Trust units. The exercise price for each option granted was not less than the market price of the Trust's units on the grant date and the contractual term of each option is not to exceed five years. Options granted before February 1, 1998 vested immediately; options granted after January 28, 1998 vested in one-third increments on the first, second and third anniversaries of their grant date. The Plan was replaced in 2001 with the Rights Plan. No additional options have been granted under the Plan since 2001. A summary of the change in the Plan during 2004 and 2003 is as follows:

	December 31, 2004		December 31, 2003	
Trust unit options	Options (000)	Weighted average price ($)	Options (000)	Weighted average price ($)
Balance – beginning of period	126	9.59	244	9.13
Granted	–	–	–	–
Exercised	(46)	9.45	(107)	8.55
Cancelled	–	–	(11)	9.42
Balance – end of period	80	9.68	126	9.59
Exercisable – end of period	80	9.68	60	9.48

The following table summarizes Plan related information at December 31, 2004:

	December 31, 2004				
	Weighted average remaining contractual life (years)	Options outstanding (000)	Weighted average exercise price ($)	Options exercisable (000)	Weighted average exercise price ($)
Range					
7.00 to 7.99	0.18	1	7.15	1	7.15
8.00 to 8.99	0.68	–	8.85	–	8.85
9.00 to 9.99	1.16	79	9.70	79	9.70
	1.16	80	9.68	80	9.68

Under the Rights Plan, employees, directors and long-term consultants may be granted rights to purchase Trust units. The exercise price for each right granted is not to be less than the market price of the Trust's units on the grant date and the contractual term of each right is not to exceed ten years. The exercise price of the rights is adjusted downwards from time to time by the amount, if any, that distributions to unitholders in any calendar quarter exceeds a percentage of the Trust's net book value of property, plant, and equipment, as determined by the Trust.

A summary of the change in the Rights Plan during 2004 and 2003 is as follows:

	December 31, 2004		December 31, 2003	
Trust unit rights	Rights (000)	Weighted average price ($)	Rights (000)	Weighted average price ($)
Balance – beginning of period	1,824	9.09	429	9.37
Granted	952	11.91	1,538	9.78
Exercised	(395)	8.49	(92)	9.05
Cancelled	(510)	9.43	(51)	9.67
Balance – before price reduction	1,871	10.56	1,824	9.72
Reduction of exercise price	–	(0.72)	–	(0.63)
Balance – end of period	1,871	9.84	1,824	9.09
Exercisable – end of period	241	8.50	47	8.58

The following table summarizes Rights Plan related information at December 31, 2004:

	December 31, 2004				
Range	Weighted average remaining contractual life (years)	Rights outstanding (000)	Weighted average exercise price ($)	Rights exercisable (000)	Weighted average exercise price ($)
7.00 to 7.99	7.17	140	7.68	52	7.68
8.00 to 8.99	8.26	808	8.38	156	8.38
9.00 to 9.99	8.45	17	9.43	5	9.49
10.00 to 10.99	8.75	83	10.59	28	10.59
11.00 to 11.99	9.39	823	11.56	–	–
	8.70	1,871	9.84	241	8.50

In conformity with CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" discussed in note 2, no compensation cost has been recognized for unit-based compensation granted prior to January 1, 2003. In accordance with the transitional provisions, the Trust has disclosed pro forma results as if the new standard had been adopted retroactively. At December 31, 2004, proforma net income and earnings per share would not have been materially different from those disclosed in the consolidated statement of operations and accumulated earnings.

The fair value of rights granted after December 31, 2002 was estimated using a Black-Scholes option-pricing model incorporating the following assumptions: risk-free interest rates ranging from 3.01 to 4.62 percent; volatility ranging from 16.14 and 22.63 percent; expected rights term of five years; and dividend yield rates ranging from 11.10 to 13.87 percent, representing the difference between the anticipated distribution and price reduction yields. The initial fair value ascribed to rights granted under the Rights Plan is not subsequently revised for changes in any of the underlying assumptions and is recorded as compensation expense evenly over the contractual vesting period. Compensation expense is adjusted prospectively for rights cancelled under the Rights Plan during the period.

The Trust recorded a recovery of compensation expense of $0.88 million during 2004 (2003 – expense of $1.24 million) related to vested rights issued under the Rights Plan with a corresponding increase to contributed surplus. When rights are exercised by employees and directors of the Trust, the consideration paid is recorded to the unitholders' investment account along with related non-cash compensation expense previously recognized in contributed surplus.

NOTE 14. SUPPLEMENTAL CASH FLOW INFORMATION

Twelve months ended December 31 ($000)	2004	2003
Cash payments related to certain items		
Interest	957	4,070
Interest on debentures	4,947	30
Interest rate swap settlement	901	–
Capital and other taxes	3,507	3,389

NOTE 15. NET CHANGE IN NON-CASH WORKING CAPITAL ITEMS

Twelve months ended December 31 ($000)	2004	2003
Change in working capital items		
Accounts receivable	(551)	1,016
Other current assets	(1,415)	(397)
Accounts payable and accrued liabilities	(8,893)	5,204
Derivatives liabilities	386	–
	(10,473)	5,823

NOTE 16. CONTRACTUAL OBLIGATIONS AND COMMITMENTS

APF is involved in certain legal actions that occurred in the normal course of business. APF is required to determine whether a contingent loss is probable and whether that loss can be reasonably estimated. When the loss has satisfied both criteria, it is charged to income. Management is of the opinion that losses, if any, arising from such legal actions would not have a material effect on these financial statements.

The Trust leases its office premises through an arrangement deemed to be an operating lease for accounting purposes. As such, the Trust is not required to record its lease obligation as a liability nor does it record its leased premises as an asset. The estimated operating lease commitments for the Trust's leased office premises for the next five years are as follows:

($000)	
2005	1,398
2006	1,213
2007	1,252
2008	1,083
2009	934
Thereafter	934

DIRECTORS and OFFICERS

Donald Engle
Independent Director and Chairman of the Board
Board Committees: Audit and Reserves, Compensation
Mr. Engle is a professional Landman (P. Land; CPL) with more than 36 years of involvement in the Canadian petroleum industry. He is President and has been a director of Welton Energy Corporation since August, 2003. He has been President of Sapphire Resources Ltd., a private consulting company since 1985. He has been a founding shareholder of a number of oil and gas companies including Grey Wolf Exploration Inc. which was listed on the TSX, where he served as President and director from 1996 to mid 2000.

William Dickson
Independent Director
Board Committees: Audit and Reserves
Mr. Dickson brings to APF Energy Trust more than 40 years' of technical, management and public company experience in the oil and gas industry. He is active as principal of Arlyn Enterprises Ltd., a private lubricants company, and serves on the Boards of APF Energy Trust, Murias Energy Corporation and IMS Petroleum Ltd. Previously, he has held senior executive or operating positions with Myriad Energy Corporation, 3D Reclamation Inc., Stampeder Exploration Ltd. and Ultramar Oil and Gas Ltd.

Daniel Mercier
Independent Director
Board Committees: Audit and Reserves, Compensation
Mr. Mercier is a professional engineer with a wealth of experience in the operation, management and capitalization of oil and gas companies. He is currently President of Asia Energy Ltd., a private Canadian company with oil and gas interests in Russia. From September, 1998 to February, 2004, he was Vice President, Operations for SOCO International plc ("SOCO"), a publicly traded UK oil and gas company. Prior thereto he was Chairman, and Chief Executive Officer of Territorial Resources, Inc., a publicly traded Colorado company engaged in international oil and natural gas exploration, which merged with SOCO on September 8, 1998. Prior to December, 1995, Mr. Mercier was President and Chief Executive Officer of Canadian Conquest Exploration, Inc., a TSX listed Canadian oil and gas company. He has been a Director of APF Energy Trust since 1996.

Robert MacDonald
Independent Director
Board Committees: Audit and Reserves, Compensation
Mr. MacDonald is an independent businessman. He has 27 years energy banking experience specializing in oil & gas financing as a senior officer of several Canadian chartered banks, with 18 years in Alberta and nine in the U.S. His experience includes debt and project financing ranging from strategic alternatives for senior, bridge and mezzanine debt structuring through portfolio management, loan workouts to credit risk management. Mr. MacDonald was Director, Oil & Gas, Commercial Banking from 1998 to 2003 with CIBC World Markets. In 1998, he was Managing Director, Koch Producer Services the merchant banking arm of a U.S. based energy company. From 1993 to 1998, he was Vice President, Oil & Gas Group with CIBC. Prior to that, Mr. MacDonald held various senior management positions within the financial services industry in the U.S. and Canada. Mr. MacDonald is a member of the Fellow of the Institute of Canadian Bankers where he graduated with honours and has a Bachelor of Business Administration, graduating with distinction. Since 2003, he has been a Director/Trustee of Newalta Income Fund and is a director-elect of another energy trust.

John Howard
Independent Director
Board Committees: Audit and Reserves
Mr. Howard is a professional engineer graduating with a B.Sc. in Chemical Engineering in 1968 from the University of Alberta. Mr. Howard has had a distinguished 35-year career in the oil and gas industry, and held senior leadership roles with Aberford Resources (President & C.E.O., 1981-87), Novalta Resources and its successor, Seagull Energy Canada (President & C.E.O., 1987-97) and Sunoma Energy (President & C.E.O., 1999-2000) / Barrington Petroleum (President & C.E.O., 1999-2001). In addition, Mr. Howard served as a Governor of the Canadian Association of Petroleum Producers (1995-97) and its predecessor, the Independent Petroleum Producers Association of Canada (1982-87) including as its Chairman (1986-87). He also served the Government of Canada as a member of the Energy Options Advisory Committee (1987-88). Mr. Howard has sat on the board of many corporations, and is currently a member of the following boards of directors: Chariot Energy Inc., Eastshore Energy Ltd., Trifecta Resources Inc., Bear Ridge Resources Ltd., Ketch Resources Ltd. (Trust) and Westrock Energy Ltd.

Martin Hislop
Chief Executive Officer, Director
Mr. Hislop is a chartered accountant with more than 25 years' experience in all aspects of financing and managing private and public oil and gas corporations, partnerships and trusts. Prior to founding the predecessor of APF Energy in September 1994, Mr. Hislop was the President and CEO of Lakewood Energy Inc., a TSX-listed oil and gas company which was created as a result of the merger of 10 limited partnerships, for whom Mr. Hislop raised in excess of $125 million in equity between 1986 and 1992. During 1984 and 1985, he provided corporate finance consulting services to a Montreal-based investment dealer. Prior to that, Mr. Hislop was Vice President, Finance for Maxwell Cummings & Sons Holdings Ltd., a private investment company. In that capacity, he participated in the creation and/or financing of several oil and gas companies in which the Cummings group took positions, including Aberford Resources and Marline Oil. Under Mr. Hislop's stewardship, APF Energy Trust has generated an average annual rate of return of 22%, placing the Trust among industry leaders.

Steven Cloutier

President and Chief Operating Officer, Director

Steven Cloutier was appointed President and Chief Operating Officer of APF Energy in 2002. From 1996 to 1998, he was Vice President, Corporate Development of APF. In 1998, he was promoted to Executive Vice President and Chief Operating Officer. Since co-founding APF, Mr. Cloutier has been directly involved in oil and gas transactions worth more than $690 million.

A native of Montreal, Quebec, Mr. Cloutier graduated in 1985 from McGill University with a bachelor's degree in industrial relations. From 1985 to 1987, Mr. Cloutier worked for a Montreal-based wealth management company. In 1986, he entered the University of Victoria Law School, from which he graduated in 1989. He commenced his legal career that year, moving to Toronto where he practised corporate law and in 1994, he moved to Calgary joining Skyridge Resources Inc., a private oil and gas company, as Vice President, Corporate Development. In 1995, Mr. Cloutier co-founded Millennium Energy Inc., a junior oil and gas company whose shares traded on the TSX Venture Exchange, and remained a director of Millennium until it was merged with Crossfield Gas Ltd. in 2003 to form Bear Creek Energy Ltd.

Alan MacDonald

Vice President, Finance and Chief Financial Officer

Mr. MacDonald is a chartered accountant with more than 24 years' experience in public practice and the oil and gas industry. From 1987 to 1999, Mr. MacDonald was Vice President, Finance of Starvest Capital Inc. which, among its other mandates, managed Starcor Energy Royalty Fund and Orion Energy Trust, two publicly-traded oil and gas royalty trusts. Most recently, he was Vice President, Finance of Due West Resources Inc., a private oil and gas company. Mr. MacDonald joined APF Energy in August 2001 and leads the team that is responsible for all financial, treasury and administrative functions for APF Energy Trust.

Dan Allan

Vice President, Exploration and Production

Mr. Allan is a professional geologist registered in both Alberta and the state of Wyoming, with more than 30 years of experience in the oil and gas industry. Following graduation with an honours degree in geology from McGill University in 1975, Mr. Allan began his career with Texaco Exploration, where he spent six years in Western Canada. In 1981 he moved to Dome Petroleum in Denver, Colorado and spent the next 14 years in the US. In 1994 he commenced employment with MAXX Petroleum as Exploration Manager and subsequently founded CanScot Resources Ltd. in 1997 as President and CEO. CanScot was acquired by APF in September of 2003. In recent years, Mr. Allan has become involved in coalbed methane ("CBM") exploration and development in both Canada and the US. In his position, Mr. Allan is responsible for overseeing the CBM division at APF Energy Trust.

Wayne Geddes

Vice President, Land

Mr. Geddes is a professional Landman and has over 23 years' experience in the oil and gas sector. Prior to joining APF Mr. Geddes was Vice President, Land & Business Development at Calver Resources Inc., a private Calgary-based unconventional gas company. From 1993 to 2002, Mr. Geddes was with Anadarko Canada Corporation and its predecessor entities (Union Pacific Resources Inc. and Norcen Energy Resources Limited), where he assumed roles of increasing responsibility, culminating in his appointment as Land Negotiations Manager. Mr. Geddes is a graduate of the University of Calgary and an active member of the Canadian Association of Petroleum Landmen, the American Association of Petroleum Landmen and has been active in CAPP on various committees.

FIVE YEAR REVIEW

(unaudited)	2004	2003	2002	2001	2000
		Restated			
FINANCIAL					
($000, except per unit amounts)					
Cash flow from operations [1]	107,126	81,019	43,789	33,995	23,706
Per unit – basic	$2.21	$2.62	$2.14	$2.70	$3.44
Distributions declared	96,930	68,713	37,766	37,311	13,899
Per unit	$2.00	$2.20	$1.810	$2.980	$1.995
Payout ratio	90%	85%	86%	110%	59%
Bank debt	169,000	98,000	88,000	59,250	25,736
Market					
High	$12.63	$12.67	$11.19	$13.40	$10.40
Low	$10.32	$9.30	$9.00	$8.75	$7.00
Close	$11.72	$12.54	$9.79	$9.85	$9.75
Average daily volume	305,706	163,000	68,700	46,500	6,900
Units outstanding (000)					
End of period	58,845	34,074	22,942	15,584	7,139
Weighted average – basic	48,486	30,970	20,470	12,578	6,888
OPERATIONS					
Daily production (average)					
Crude oil (bbl)	6,969	6,472	5,307	3,167	1,152
NGLs (bbls)	758	358	144	100	254
Natural gas (mcf)	49,712	33,799	18,488	15,391	13,449
Total (boe)	16,012	12,463	8,532	5,832	3,648
Average commodity sales prices ($Cdn.)					
Total crude oil (per bbl)	$44.63	$ 36.07	$35.82	$32.20	$42.67
NGLs (per bbl)	$6.79	$6.64	$ 3.78	$5.25	$4.89
Natural gas (per mcf)	$40.09	$31.83	$25.15	$30.97	$35.96
Average (per boe) [3]	$42.40	$37.66	$30.89	$31.87	$34.01
Operating netbacks per boe (before derivatives)	$25.42	$23.40	$18.53	$19.44	$21.61
Proved plus probable reserves [2]					
Crude oil & NGLs (mbbl)	30,498	23,789	20,608	13,545	5,648
Natural gas (mmcf)	169,412	99,197	68,290	50,984	46,364
Total (mboe) [3]	58,733	40,322	31,989	22,042	13,375
Reserve life index (years)	8.9	8.9	10.3	10.4	10.0

(1) Management uses cash flow (before changes in non-cash working capital) to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital.

(2) 2000 to 2002 reserve numbers are based on established (proved plus 50 percent probable) company interest reserves prior to royalties and 2003 to 2004 reserves are based on total proved plus probable company interest reserves prior to royalties as defined in National Instrument 51-101 ("NI-51-101").

(3) BOE's may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio for natural gas of 6 Mcf: 1 bbl has been used which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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Computershare Trust Company of Canada

AUDITORS
PricewaterhouseCoopers LLP

STOCK EXCHANGE LISTING
Toronto Stock Exchange
Symbols: AY.UN and AY.DB

DIRECTORS AND OFFICERS

Donald Engle
Independent Director and
Chairman of the Board (1) (2)

William Dickson
Independent Director (1)

John Howard
Independent Director (1)

Daniel Mercier
Independent Director (1) (2)

Robert MacDonald
Independent Director (1) (2)

Martin Hislop
Director
Chief Executive Officer

Steven Cloutier
Director
President & Chief Operating Officer

Alan MacDonald
Vice President, Finance & Chief Financial Officer

Dan Allan
Vice President, Exploration and Production

Wayne Geddes
Vice President, Land

(1) Member of Audit and Reserves Committee
(2) Member of Compensation Committee

ABBREVIATIONS

ARTC	Alberta Royalty Tax Credit	mmbtu	million British thermal units
bbl	barrel	mcf	thousand cubic feet
bcf	billion cubic feet	mmcf	million cubic feet
boe	barrels of oil equivalent*	mcf/d	thousand cubic feet per day
boe/d	barrels of oil equivalent per day*	mmcf/d	million cubic feet per day
CBM	coalbed methane	NGL	natural gas liquid
mbbls	thousand barrels	NPV	net present value
mmbbls	million barrels	tcf	trillion cubic feet
mboe	thousand barrels of oil equivalent*	WTI	West Texas Intermediate
mmboe	million barrels of oil equivalent*		

* BOE's may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio for natural gas of 6 Mcf: 1 bbl has been used which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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